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SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF  
THE SECURITIES EXCHANGE ACT OF 1934  
For the fiscal year ended December 31, 2002

Commission File Number 0-7246

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

PETROLEUM DEVELOPMENT CORPORATION  
(Exact name of registrant as specified in its charter)

Nevada  
(State or other jurisdiction of  
incorporation or organization)

95-2636730  
(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:

Petroleum Development Corporation Common Stock, \$.01 par value  
(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

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

As of March 5, 2003, 15,734,767 shares of the Registrant's Common Stock were issued and outstanding, and the aggregate market value of such shares held by non-affiliates of the Registrant on such date was \$67,881,269 (based on the last traded price of \$5.80).

DOCUMENTS INCORPORATED BY REFERENCE

Document  
Proxy

Form 10-K Part III  
Items 10, 11, 12, and 13  
(except as presented herein)

## PART I

### Item 1. Business

The Company is an independent energy company engaged primarily in the development, production and marketing of natural gas and oil. The Company has grown primarily through drilling and development activities, the acquisition of natural gas and oil producing wells and the expansion of its natural gas marketing activities. As of December 31, 2002, the Company operates approximately 2,200 wells located in the Appalachian basin, Michigan, and the Rocky Mountain Region, with gross proved reserves of 364 billion cubic feet equivalent of natural gas ("Bcfe", based on one barrel of oil equals 6 thousand cubic feet equivalent of natural gas ("Mcf")) of which the Company's share is 141 Bcfe. The wells operated by the Company currently produce an aggregate of approximately 55,000 thousand cubic feet equivalent of gas per day, of which the Company's share is approximately 21,500 Mcfe.

The Company's operations are divided into three regions, the Appalachian Basin, Michigan Basin, and the Rocky Mountain Region. The Company has conducted operations in Appalachian Basin since its inception in 1969, in Michigan Basin since 1997, and the Rocky Mountain Region since 1999. During 2002 approximately 27% of production was generated by Appalachian Basin wells, 28% by Michigan Basin wells and 45% by Rocky Mountain wells. As of the end of 2002, the Company's total proved reserves were located as follows: Appalachian Basin 32%, Michigan Basin 20% and Rocky Mountain Region 48%. The majority of the Company's undeveloped reserves are in the Rocky Mountain Region and the planned drilling for 2003 will be focused in that area.

In all three regions the Company has historically targeted shallow, developmental natural gas reserves for development. In some areas of the Rocky Mountain Region, Michigan and the Appalachian Basin the wells also produce oil in conjunction with natural gas.

The Company owns Riley Natural Gas (RNG), a natural gas marketing company, which aggregates and resells natural gas developed by the Company and other producers. This allows the Company to diversify its operations beyond natural gas drilling and production. RNG has established relationships with many of the natural gas producers in the Appalachian Basin and has significant expertise in the natural gas end-user market. In addition, RNG has extensive experience in the use of hedging strategies, which the Company utilizes to manage the financial impact on the Company of changes in the price of natural gas.

Since 1984, the Company has sponsored limited partnerships formed to engage in drilling operations. The Company typically purchases a 20% ownership interest in these drilling limited partnerships. In 2002, the Company, through four public drilling partnerships, raised \$56.9 million making it the sponsor of the largest public oil and gas partnership program in the United States as it has been for the last several years. The drilling programs have provided the Company with access to the capital resources necessary to expand its drilling opportunities and to maintain the infrastructure necessary to support such activities.

#### Available Information

The Company's Internet address is [www.petd.com](http://www.petd.com). Electronic copies of the Company's annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, and amendments to those reports are available free of charge by visiting the "Investor Relations - Edgar Link" section of [www.petd.com](http://www.petd.com). These reports are posted as soon as reasonably practicable after they are electronically filed with the Securities and Exchange Commission.

#### Industry Overview

Natural gas is the second largest energy source in the United States, after liquid petroleum. The 21.5 Tcf of natural gas consumed in 2002 represented approximately 23% of the total energy used in the United States. Natural gas is consumed in the United States as follows: 37% by industrial end-users as feedstock for products such as plastic and fertilizer or as the energy source for producing products such as glass; 23% and 15% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; and 25% by utilities for the generation of electricity. (Source U.S. Energy Information Administration)

The Company believes that the market for natural gas will grow in the future. The demand for natural gas has increased due to four main factors:

**Efficiency.** Relative to other energy sources, natural gas losses during transportation from source to destination are slight, averaging only about 9% of the natural gas energy.

**Environmentally favorable.** Natural gas is the cleanest and most environmentally safe of the fossil fuels.

**Safety.** The delivery of natural gas is among the safest means of distributing energy to customers, as the natural gas transmission system is fixed and is located underground.

**Price.** The deregulation of the natural gas industry and a favorable regulatory environment have resulted in end-users' ability to purchase natural gas on a competitive basis from a greater variety of sources.

The Company believes that the foregoing factors, together with the increased availability of natural gas as a form of energy for residential, commercial and industrial uses, should increase the demand for natural gas as well as create new markets for natural gas.

As local supplies of natural gas are inadequate to meet demand in certain sections of the country, the West Coast and the Northeast import natural gas from producing areas via interstate natural gas pipelines. The cost of transporting natural gas from the major producing areas to markets creates a price advantage for production located closer to the consuming regions. The natural gas industry in the Appalachian Basin and Michigan benefit from proximity to the northeastern United States. In contrast, much of the production in the Rocky Mountains is transported significant distances to end use markets.

In the early 1980's, natural gas companies began exploiting the northern portion of Michigan's lower peninsula, when certain favorable tax credits for natural gas development were enacted. The result of such development was new advances in drilling technology, which made natural gas drilling in this area profitable even after the expiration of these tax credits. In Michigan's lower peninsula, there is an abundance of shallow Antrim gas shale, which can provide significant reserves per well drilled. Additionally, this area is close to certain end-user markets, which has provided favorable premiums in gas sales prices.

During 1998 the Company began to establish a lease position in the Rocky Mountain producing region. The region is believed to hold substantial undeveloped natural gas resources. Recent and planned additions to pipeline capacity in the region have made the area more attractive for development. Gas from the region will generally sell for less than gas in the Appalachian and Michigan Basins, but costs of development are expected to be less. The Company currently has over 150 development locations in the Wattenberg field in the DJ Basin, and 63,000 acres available for development in the Piceance Basin, both basins are located in Colorado.

#### Business Strategy

The Company's objective is to expand its natural gas reserves, production and revenues through a strategy that includes the following key elements:

Expand drilling operations. For its size, the Company has had one of the most active drilling programs in the country. The Company drilled 70 wells in 2002, compared to 141 wells in 2001. The Company believes that it will be able to drill a substantial number of new wells on its current undeveloped leased properties. As of December 31, 2002, the Company had leases or other development rights to 3,500 undeveloped acres in the Michigan Basin, 950 undeveloped acres in the Appalachian Basin and 69,300 undeveloped acres in the Rocky Mountain Region. As drilling activity increases, the Company benefits as its fixed costs may be spread over a larger number of wells.

Acquire producing properties. The Company's acquisition efforts are focused on properties that fit well within existing operations or that help to build critical mass in areas where the Company is establishing new operations. Acquisitions will likely offer economies in management and administration, and therefore the Company believes that it will be able to acquire more producing wells without incurring substantial increases in its administrative costs.

Pursue geographic expansion. The Company has proven its ability to drill and operate in geographically diverse domestic areas. Since 1996, the Company expanded its operations from the Appalachian Basin, first to Michigan, and more recently to the Rocky Mountains. In 2002 over two-thirds of the Company's production was generated in the two newer regions. The Company plans to conduct the majority of its drilling activities in the Rocky Mountain region during 2003, but will continue to seek additional opportunities for expansion to areas where the Company's experience and expertise can be applied successfully.

Reduce risks inherent in natural gas development and marketing. An integral part of the Company's strategy has been and will continue to be to concentrate on shallow development, (rather than exploratory) drilling, and geographical diversification to reduce risk levels associated with natural gas and oil production. Development drilling is less risky than exploratory drilling and is likely to generate cash returns more quickly. The focus on shallow wells builds on the Company's knowledge and experience, and also provides greater investment diversification than an equal investment in a smaller number of deeper and/or more expensive wells. Geographical diversification can help to offset possible weakness in the natural gas market or disappointing drilling results in one area. The Company believes that successful natural gas marketing is essential to profitable operations in a deregulated gas market. To further this goal, the Company has the expertise of RNG, an experienced natural gas marketer. The Company also uses natural gas and oil hedges to reduce the effects of volatility of energy prices. The Company intends to continue to expand its marketing capabilities to keep pace with the changing natural gas industry.

#### Exploration and Development Activities

The Company's development activities focus on the identification and drilling of new productive wells and the acquisition of existing producing wells from other producers.

#### Prospect Generation

The Company's staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. These geologists have decades of cumulative experience drilling natural gas and oil wells. They utilize results from logs and other tools to evaluate existing wells and to predict the location of attractive new gas reserves. To further this process, the Company has collected and continues to collect logs, core data, production information and other raw data available from state and private agencies, other companies and individuals actively drilling in the regions being evaluated. From this information the geologists develop models of the subsurface structures and formations that are used to predict areas with above-average prospects for economic development.

On the basis of these models, the geologists instruct the Company's land department to obtain available natural gas leaseholds, farmouts and other development rights in these prospective areas. These rights are then obtained, if possible, by the Company's land department or contract landmen under the direction of the Company's land manager. In most cases, the Company pays a lease bonus and annual rental payments, converting, upon initiation of production, to a royalty on gross production revenue in return for obtaining the leases. In addition overriding royalty payments may be made to third parties in conjunction with the acquisition of drilling rights initially leased by others. As of December 31, 2002, the Company had a total leasehold inventory of approximately 183,950 acres. See--"Properties--Oil and Natural Gas Leases."

#### Drilling Activities

When prospects have been identified and leased, the Company develops these properties by drilling wells. In 2002, the Company drilled a total of 70 wells all of which were successfully completed as producing wells. Typically, the Company will act as driller-operator for these prospects, entering into contracts with partnerships, primarily Company-sponsored partnerships, and other entities that are interested in exploration or development of the prospects. The Company generally retains an interest in each well it drills. See "Financing of Drilling Activities."

Much of the work associated with drilling, completing and connecting wells, including drilling, fracturing, logging and pipeline construction, is performed by subcontractors specializing in those operations, as is common in the industry. A large part of the material and services used by the Company in the development process is acquired through competitive bidding by approved vendors. The Company also directly negotiates rates and costs for services and supplies when conditions indicate that such an approach is warranted. As the prices paid to the Company by its investor partners for the Company's services are frequently fixed before the wells are drilled or are determined solely on the well depth, the Company is subject to the risk that prices of goods or services used in the development process could increase, rendering its contracts with its investor partners less profitable or unprofitable. In addition, problems encountered in the process can substantially increase development costs, sometimes without recourse for the Company to recover its costs from its partners. To minimize these risks, the Company seeks to lock in its development costs in advance of drilling and, when possible, at the time of negotiation and execution of its investor partnership agreements.

#### Acquisitions of Producing Properties

In addition to drilling new wells, the Company continues to pursue opportunities to purchase existing wells from other producers and greater ownership interests in the wells it operates. Generally, outside interests purchased include a majority interest in the wells and well operations.

During 1999, the Company purchased a 100% working interest in 53 producing wells in the D-J Basin of Colorado which added 3.6 Bcf of natural gas and 370,000 barrels of oil to the Company's reserves. During 2000, the Company purchased 100% of the working interest in 168 producing wells in the DJ Basin of Colorado which added 4.9 Bcf of natural gas and 560,000 barrels of oil to the Company's reserves. Certain well interests in its Company sponsored partnerships were also purchased in 2002, 2001 and 2000.

## Production

The following table shows the Company's net production in Bbls of crude oil and in Mcf of natural gas and the costs and weighted average selling prices thereof, for the last five years.

	Year Ended December 31,				
	<u>2002</u>	<u>2001</u>	<u>2000</u>	<u>1999</u>	<u>1998</u>
Production(1):					
Oil(MBbls)	227	195	109	8	8
Natural Gas (MMcf)	6,462	6,085	5,737	3,451	2,453
Equivalent MMcfs(2)	7,824	7,255	6,391	3,499	2,501
Average sales price:					
Oil (per Bbl)	\$24.41	\$22.53	\$29.99	\$18.75	\$10.61
Natural gas (per Mcf)(3)	\$2.68	\$3.53	\$2.74	\$2.46	\$2.46
Average production cost (lifting cost)					
Per equivalent Mcf(4)	\$0.82	\$0.83	\$0.66	\$0.69	\$0.61

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(1) Production as shown in the table is net to the Company and is determined by multiplying the gross production volume of properties in which the Company has an interest by the percentage of the leasehold or other property interest owned by the Company.

(2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one barrel of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcfs of natural gas.

(3) The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price volatility of its natural gas sales. The effect of hedges on the average sales price of natural gas for the years ended December 31, 2002, 2001, 2000, 1999 and 1998 was \$0.02, \$(0.56), \$(0.91), \$(0.01) and \$0.14, respectively.

(4) Production costs represent oil and gas operating expenses as reflected in the financial statements of the Company.

## Well Operations

The Company currently operates approximately 1,502 wells in the Appalachian Basin, 204 wells in the Michigan Basin and 463 wells in the Rocky Mountain Region. The Company's ownership interest in these wells ranges from 0% to 100%, and, on average, the Company has an approximate 50% ownership interest in the wells it operates. Currently these wells produce an aggregate of about 55,000 Mcfe of natural gas per day, including the Company's share of 21,500 Mcfe per day.

The Company is paid a monthly operating charge for each well it operates for outside owners. The rate is competitive with rates charged by other operators in the area. The charge covers monthly operating and accounting costs, insurance and other recurring costs. The Company may also receive additional compensation for special non-recurring activities, such as reworks and recompletions.

## Transportation

Natural gas wells are connected by pipelines to natural gas markets. Over the years, the Company has developed extensive gathering systems in some of its areas of operations. The Company also continues to construct new trunklines as necessary to provide for the marketing of natural gas being developed from new areas and to enhance or maintain its existing systems.

The Company is paid a transportation fee for natural gas that is moved by other shippers through these pipeline systems. In many cases the Company has been able to receive higher natural gas prices as a result of its ability to move natural gas to more attractive markets through this pipeline system, to the benefit of both the Company and its investor partners.

## Item 2. Properties

### Drilling Activity

The following table summarizes the Company's development drilling activity for the years ended December 31, 1998, 1999, 2000, 2001 and 2002. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. The Company's exploratory wells drilled in the past five years consist of one dry hole (0.19 net) drilled in 1998 and five dry holes (2.44 net) drilled in 1999.

	Development Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
1998	212	56.99	201	54.22	11	2.77
1999	173	54.64	165	53.10	8	1.54
2000	97	27.39	97	27.39	-	-
2001	141	40.00	135	37.94	6	2.06
2002	<u>70</u>	<u>13.71</u>	<u>70</u>	<u>13.71</u>	<u>-</u>	<u>-</u>
Total	<u>693</u>	<u>192.73</u>	<u>668</u>	<u>186.36</u>	<u>25</u>	<u>6.37</u>

### Summary of Productive Wells

The table below shows the number of the Company's productive gross and net wells at December 31, 2002.

Location	Productive Wells			
	Gas		Oil	
	Gross	Net	Gross	Net
Colorado	458	265.70	-	-
Michigan	197	109.23	7	2.66
North Dakota	-	-	5	1.83
Ohio	11	3.42	-	-
Pennsylvania	531	165.76	-	-
Tennessee	1	0.71	36	13.62
West Virginia	<u>919</u>	<u>518.27</u>	<u>4</u>	<u>1.72</u>
Total	<u>2,117</u>	<u>1,063.09</u>	<u>52</u>	<u>19.83</u>

### Reserves

All of the Company's oil and natural gas reserves are located in the United States. The Company's approximate net proved reserves were estimated by Wright & Company, Inc. independent petroleum engineers ("Wright & Company"), to be 128,851,000 Mcf of natural gas and 2,073,000 Bbls of oil at December 31, 2002, 118,608,000 Mcf of natural gas and 2,126,000 Bbls of oil at December 31, 2001 and 118,640,000 Mcf of natural gas and 2,166,000 Bbls of oil at December 31, 2000.

The Company's approximate net proved developed reserves were estimated, by Wright & Company to be 94,847,000 Mcf of natural gas and 1,849,000 Bbls of oil at December 31, 2002, 88,477,000 Mcf of natural gas and 1,801,000 Bbls of oil at December 31, 2001 and 92,131,000 Mcf of natural gas and 1,527,000 Bbls of oil at December 31, 2000.

The Company's reserves by region are as follows as of December 31, 2002:

	Oil (Mbbl)	Gas (Mmcf)	Natural Gas Equivalent (Mmcfe)	%
<u>Proved Developed Reserves</u>				
Appalachian Basin	46	45,216	45,492	42.94%
Michigan Basin	48	26,671	26,959	25.45%
Rocky Mountain Region	<u>1,755</u>	<u>22,960</u>	<u>33,490</u>	<u>31.61%</u>
Total Proved Developed Reserves	1,849	94,847	105,941	100.00%
<u>Proved Undeveloped Reserves</u>				
Appalachian Basin	0	0	0	0.00%
Michigan Basin	0	1,488	1,488	4.21%
Rocky Mountain Region	<u>224</u>	<u>32,516</u>	<u>33,860</u>	<u>95.79%</u>
Total Proved Undeveloped	224	34,004	35,348	100.00%
<u>Total Proved Reserves</u>				
Appalachian Basin	46	45,216	45,492	32.20%
Michigan Basin	48	28,159	28,447	20.13%
Rocky Mountain Region	<u>1,979</u>	<u>55,476</u>	<u>67,350</u>	<u>47.67%</u>
Total Proved Reserves	2,073	128,851	141,289	100.00%

No major discovery or other favorable or adverse event that would cause a significant change in estimated reserves is believed by the Company to have occurred since December 31, 2002. Reserves cannot be measured exactly, as reserve estimates involve subjective judgment. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes.

The standardized measure of discounted future estimated net cash flows attributable to the Company's proved oil and gas reserves, giving effect to future estimated income tax expenses, was estimated by Wright & Company to be \$98.5 million as of December 31, 2002, \$46.4 million as of December 31, 2001 and \$104.6 million as of December 31, 2000. These amounts are based on year-end prices, adjusted for hedging contracts at the respective dates. The values expressed are estimates only, and may not reflect realizable values or fair market values of the natural gas and oil ultimately extracted and recovered. The standardized measure of discounted future net cash flows may not accurately reflect proceeds of production to be received in the future from the sale of natural gas and oil currently owned and does not necessarily reflect the actual costs that would be incurred to acquire equivalent natural gas and oil reserves.



## Net Proved Natural Gas and Oil Reserves

The proved reserves of natural gas and oil of the Company as estimated by Wright & Company at December 31, 2002 are set forth below. These reserves have been prepared in compliance with the rules of the Securities and Exchange Commission (the "SEC") based on year-end prices. An analysis of the change in estimated quantities of natural gas and oil reserves from January 1, 2002 to December 31, 2002, all of which are located within the United States, is shown below:

	<u>Natural Gas (Mcf)</u>	<u>Oil (Bbls)</u>
Proved developed and undeveloped reserves:		
Beginning of year	118,608,000	2,126,000
Revisions of previous estimates	<u>1,469,000</u>	<u>124,000</u>
Beginning of year as revised	120,077,000	2,250,000
New discoveries and extensions		
Rocky Mountain region	19,607,000	130,000
Dispositions to partnerships	(4,792,000)	(80,000)
Acquisitions		
Michigan	4,000	-
Rocky Mountain region	75,000	-
Appalachian basin	342,000	-
Production	<u>(6,462,000)</u>	<u>(227,000)</u>
End of year	<u>128,851,000</u>	<u>2,073,000</u>
Proved developed reserves:		
Beginning of year	<u>88,477,000</u>	<u>1,801,000</u>
End of year	<u>94,847,000</u>	<u>1,849,000</u>

## Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Natural Gas and Oil Reserves

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves. Future cash inflows are computed by applying year-end prices, adjusted for any hedging contracts, of natural gas and oil relating to the Company's proved reserves to year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs, assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at December 31, 2002 to the future pretax net cash flows, less the tax basis of the properties, and gives effect to permanent differences, tax credits and allowances related to the properties.

	<u>As of</u> <u>December 31, 2002</u>
Future estimated revenues	\$ 548,949,000
Future estimated production costs	(143,878,000)
Future estimated development costs	(50,971,000)
Future estimated income tax expense	<u>(105,876,000)</u>
Future net cash flows	248,224,000
10% annual discount for estimated timing of cash flows	<u>(149,755,000)</u>
Standardized measure of discounted future estimated net cash flows	\$ <u>98,469,000</u>

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows from January 1, 2002 through December 31, 2002:

Sales of oil and natural gas production, net of production costs	\$(16,449,000)
Net changes in prices and production costs	143,574,000
Extensions, discoveries and improved recovery, less related costs	39,347,000
Dispositions to partnerships	(6,940,000)
Acquisitions	1,167,000
Development costs incurred during the period	16,429,000
Revisions of previous quantity estimates	3,318,000
Changes in estimated income taxes	(55,516,000)
Accretion in discount	<u>(72,900,000)</u>
	<u>\$52,030,000</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, as 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 and the limitations inherent therein.

Substantially all of the Company's natural gas and oil reserves have been mortgaged or pledged as security for the Company's credit agreement. See Note 3 of Notes to Consolidated Financial Statements.

#### Oil and Natural Gas Leases

The following table sets forth, as of December 31, 2002, the acres of developed and undeveloped oil and natural gas acreage leased and available to the Company, listed alphabetically by state.

	Developed <u>Acreage</u>	Undeveloped <u>Acreage</u>
Colorado	21,200	62,700
Michigan	23,900	3,500
North Dakota	1,700	6,600
Ohio	400	-
Pennsylvania	9,000	350
Tennessee	5,400	-
West Virginia	<u>48,600</u>	<u>600</u>
Total	<u>110,200</u>	<u>73,750</u>

#### Title to Properties

The Company believes that it holds good and indefeasible title to its properties, in accordance with standards generally accepted in the natural gas industry, subject to such exceptions stated in the opinion of counsel employed in the various areas in which the Company conducts its exploration activities, which exceptions, in the Company's judgment, do not detract substantially from the use of such property. As is customary in the natural gas industry, only a perfunctory title examination is conducted at the time the properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, an extensive title examination is conducted and curative work is performed with respect to defects which the Company deems to be significant. A title examination has been performed with respect to substantially all of the Company's producing properties. No single property owned by the Company represents a material portion of the Company's holdings.

The properties owned by the Company are subject to royalty, overriding royalty and other outstanding interests customary in the industry. The properties are also subject to burdens such as liens incident to operating agreements, current taxes, development obligations under natural gas and oil leases, farm-out arrangements and other encumbrances, easements and restrictions. The Company does not believe that any of these burdens will materially interfere with the use of the properties.

#### Natural Gas Sales

Natural gas is sold by the Company under contracts with terms ranging from one month to three years. Virtually all of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, the Company's revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. The Company believes that the pricing provisions of its natural gas contracts are customary in the industry.

The Company sells its natural gas to industrial end-users and utilities. Two customers, Cinnabar Energy Services and Duke Energy accounted for 21.1% and 11.0%, respectively of the Company's revenues from oil and gas sales (10.8% and 5.6% of total revenues) in 2002. One customer, Cinnabar Energy Services, accounted for 25.2% and 17.7% of the Company's revenues from oil and gas sales (13.1% and 11.3% of total revenues) in 2001 and 2000, respectively. No other single purchaser of the Company's natural gas accounted for 10% or more of the Company's total revenues during 2002, 2001 or 2000.

At December 31, 2002, natural gas produced by the Company sold at prices per Mcf ranging from \$0.90 to \$5.93, depending upon well location, the date of the sales contract and other factors. The weighted net average price of natural gas sold by the Company during 2002 was \$2.68 per Mcf.

In general, the Company, together with its marketing subsidiary, RNG, has been and expects to continue to be able to produce and sell natural gas from its wells without significant curtailment by providing natural gas to purchasers at competitive prices. Open access transportation on the country's interstate pipeline system has greatly increased the range of potential markets. Whenever feasible the Company allows for multiple market possibilities from each of its gathering systems, while seeking the best available market for its natural gas at any point in time.

#### Oil Sales

The Company's acquisition in December 1999 of 53 wells and in April 2000 of 108 wells in the Wattenberg field in Colorado and ongoing development activities in the Rocky Mountains added to oil production and reserves. At the end of 2002 oil was about 9% of the Company's total equivalent reserves.

The Company is currently able to sell all the oil that it can produce under existing sales contracts with petroleum refiners and marketers. The Company does not refine any of its oil production. The Company's crude oil production is sold to purchasers at or near the Company's wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the oil industry. One purchaser, Teppco Crude Oil, L.P. accounted for 11.9% of the Company's revenues from oil and gas sales (5.6% of total revenues) in 2002. No customer accounted for more than 10% of the Company's revenues from oil and gas sales in 2001 or 2000. At December 31, 2002, oil produced by the Company sold at prices ranging from \$23.93 to \$28.64 per barrel, depending upon the location and quality of oil. In 2002, the weighted net average price per barrel of oil sold by the Company was \$24.41.

Oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of oil spills. Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to procure and implement spill prevention, control, counter-measures and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Operations of the Company are also subject to the Federal Clean Water Act and analogous state laws relating to the control of water pollution, which laws provide varying civil and criminal penalties and liabilities for release of petroleum or its derivatives into surface waters or into the ground.

#### Natural Gas Marketing

The Company's natural gas marketing activities involve the aggregation and reselling of natural gas produced by the Company and others. The Company believes that in a deregulated market, successful natural gas marketing is essential to profitable operations. A variety of factors affect the market for natural gas, including the availability of other domestic production, natural gas imports, the availability and price of alternative fuels, the proximity and capacity of natural gas pipelines, general fluctuations in the supply and demand for natural gas and the effects of state and federal regulations on natural gas production and sales. The natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers.

RNG, a wholly owned subsidiary, is a natural gas marketing company that specializes in the acquisition, aggregation and marketing of natural gas production in the Company's operating areas. RNG markets natural gas produced by the Company and also purchases natural gas from other producers and resells to utilities, end users or other marketers. The employees of RNG have extensive knowledge of natural gas markets in the Company's areas of operations. Such knowledge assists the Company in maximizing its prices as it markets natural gas from Company-operated wells. The gas is marketed to natural gas utilities, pipelines and industrial and commercial customers, either directly through the Company's gathering system, or utilizing transportation services provided by regulated interstate pipeline companies.

#### Hedging Activities

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price volatility stemming from its natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures and option contracts for Appalachian and Michigan production, and 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 twelve-month period. Company policy prohibits the use of natural gas futures or options for speculative purposes and permits utilization of hedges only if there is an underlying physical position.

The Company has extensive experience with the use of financial hedges to reduce the risk and impact of natural gas price changes. These hedges are used by RNG to coordinate fixed and variable priced purchases and sales, and by the Company to "lock in" fixed prices from time to time for the Company'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 future 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 Company is subject to price fluctuations for natural gas sold in the spot market. The Company continues to evaluate the potential for reducing these risks by entering into hedge transactions. In addition, the Company may also close out any portion of hedges that may exist from time to time which may result in a gain or loss on that hedge transaction. There are no hedge contracts outstanding as of December 31, 2002 related to oil production.

## Financing of Drilling Activities

The Company conducts development drilling activities for its own account and for other investors. In 1984, the Company began sponsoring private drilling limited partnerships, and, in 1989, the Company began to register the partnership interests offered under public drilling programs with the SEC. The Company's public partnerships had \$56.9 million in subscriptions in 2002, \$57.1 million in subscriptions in 2001 and \$55.6 million in 2000. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 20% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. While funds were received by the Company pursuant to drilling contracts in the years indicated, the Company recognizes revenues from drilling operations on the percentage of completion method as the wells are drilled, rather than when funds are received. Most of the Company's drilling and development funds now are received from partnerships in which the Company serves as managing general partner. However, because wells produce for a number of years, the Company continues to serve as operator for a number of unaffiliated parties. In addition to the partnership structure, the Company also utilizes joint venture arrangements for financing drilling activities.

The financing process begins when the Company enters into a development agreement with an investor partner, pursuant to which the Company agrees to assign its rights in the property to be drilled to the partnership or other entity. The partnership or other entity thereby becomes owner of a working interest in the property.

The Company's development contracts with its investor partners have historically taken many different forms. Generally the agreements can be classified as on a "footage-based" rate, whereby the Company receives drilling and completion payments based on the depth of the well; "cost-plus," in which the Company is reimbursed for its actual cost of drilling plus some additional amount for overhead and profit; or "turnkey," in which a specified amount is paid for drilling and another amount for completion. As part of the compensation for its services, the Company also has received some interest in the production from the well in the form of an overriding royalty interest, working interest or other proportionate share of revenue or profits. The Company's development contracts may provide for a combination of several of the foregoing payment options. Basic drilling and completion operations are performed on a footage-based rate, with leases and gathering pipelines being contributed at Company cost. The Company may also purchase a working interest in the subject properties.

The level of the Company's drilling and development activity is dependent upon the amount of subscriptions in its public drilling partnerships and investments from other partnerships or other joint venture partners. The use of partnerships and similar financing structures enables the Company to diversify its holdings, thereby reducing the risks of its development investments. Additionally, the Company benefits through such arrangements by its receipt of fees for its management services and/or through an increased share in the revenues produced by the developed properties. The Company believes that investments in drilling activities, whether through Company-sponsored partnerships or other sources, are influenced in part by the favorable treatment that such investments enjoy under the federal income tax laws. No assurance can be given that the Company will continue to have access to funds generated through these financing vehicles.

## Governmental Regulation

The Company's business and the natural gas industry in general are heavily regulated. The availability of a ready market for natural gas production depends on several factors beyond the Company's control. These factors include regulation of natural gas production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to prevent waste of natural gas, protect rights to produce natural gas between owners in a common reservoir and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. The Company takes the steps necessary to comply with applicable regulations both on its own behalf and as part of the services it provides to its investor partnerships. The Company believes that it is in substantial compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. The following discussion of the regulation of the United States natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which the Company's operations may be subject.

## Regulation of Oil and Natural Gas Exploration and Production

The Company's oil and natural gas operations are subject to various types of regulation at the federal, state and local levels. Prior to commencing drilling activities for a well, the Company must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. Such permits and approvals include those for the drilling of wells, and such regulation includes maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. The Company's operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore, more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the rateability of production. The effect of these regulations may limit the amount of oil and natural gas the Company can produce from its wells and may limit the number of wells or the locations at which the Company can drill. The regulatory burden on the oil and natural gas industry increases the Company's costs of doing business and, consequently, affects its profitability. In as much as such laws and regulations are frequently expanded, amended and reinterpreted, the Company is unable to predict the future cost or impact of complying with such regulations.

## Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (the "NGPA") and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC). Maximum selling prices of certain categories of natural gas sold in "first sales," whether sold in interstate or intrastate commerce, were regulated pursuant to the NGPA. The Natural Gas Wellhead Decontrol Act (the "Decontrol Act") removed, as of January 1, 1993, all remaining federal price controls from natural gas sold in "first sales" on or after that date. FERC's jurisdiction over natural gas transportation was unaffected by the Decontrol Act. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at market prices, Congress could reenact price controls in the future.

The Company's sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In recent years, FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No.636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No.636 require that interstate pipelines provide transportation separate or "unbundled" from their sales service, and require that pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers. In many instances, the result of Order No.636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. Another effect of regulatory restructuring is the greater transportation access available on interstate pipelines. In some cases, producers and marketers have benefited from this availability. However, competition among suppliers has greatly increased and traditional long-term producer-pipeline contracts are rare. Furthermore, gathering facilities of interstate pipelines are no longer regulated by FERC, thus allowing gatherers to charge higher gathering rates.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue. The Company cannot determine to what extent future operations and earnings of the Company will be affected by new legislation, new regulations, or changes in existing regulation, at federal, state or local levels.

## Environmental Regulations

The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stricter environmental legislation and regulations could continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the natural gas industry in general, the business and prospects of the Company could be adversely affected.

The Company generates wastes that may be subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by the Company's operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases numerous properties that for many years have been used for the exploration and production of oil and natural gas. Although the Company believes that it has utilized good operating and waste disposal practices, prior owners and operators of these properties may not have utilized similar practices, and hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws as well as state laws governing the management of oil and natural gas wastes. Under such laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for release of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company's operations may be subject to the Clean Air Act ("CAA") and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company. The EPA and states have been developing regulations to implement these requirements. The Company may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues.

The Company's expenses relating to preserving the environment during 2002 were not significant in relation to operating costs and the Company expects no material change in 2003. Environmental regulations have had no materially adverse effect on the Company's operations to date, but no assurance can be given that environmental regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on the Company's business, financial condition or results of operations.

As a matter of corporate policy and commitment, the Company attempts to minimize the adverse environmental impact of all its operations. During the 1990's, the Company was a nine-time recipient of the West Virginia Department of Environmental Protection's top award in recognition of the quality of the Company's environmental and reclamation work in its drilling activities.

## Operating Hazards and Insurance

The Company's exploration and production operations include a variety of operating risks, including the risk of fire, explosions, blowouts, craterings, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of toxic gas, the occurrence of any of which could result in substantial losses to the Company due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. The Company's pipeline, gathering and distribution operations are subject to the many hazards inherent in the natural gas industry. These hazards include damage to wells, pipelines and other related equipment, and surrounding properties caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any significant problems related to its facilities could adversely affect the Company's ability to conduct its operations. In accordance with customary industry practice, the Company maintains insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event not fully insured against could materially adversely affect the Company's operations and financial condition. The Company cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

## Competition

The Company believes that its exploration, drilling and production capabilities and the experience of its management and professional staff generally enable it to compete effectively. The Company encounters competition from numerous other oil and natural gas companies, drilling and income programs and partnerships in all areas of its operations, including drilling and marketing natural gas and obtaining desirable natural gas leases. Many of these competitors possess larger staffs and greater financial resources than the Company, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. The Company's ability to explore for oil and natural gas prospects and to acquire additional properties in the future depends upon its ability to conduct its operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. The Company competes with a number of other companies, which offer interests in drilling partnerships with a wide range of investment objectives and program structures. Competition for investment capital for both public and private drilling programs is intense. The Company also faces intense competition in the marketing of natural gas from competitors including other producers as well as marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic oil and natural gas exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future. Factors affecting competition in the natural gas industry include price, location, availability, quality and volume of natural gas. The Company believes that it can compete effectively in the oil and natural gas industry on each of the foregoing factors. Nevertheless, the Company's business, financial condition or results of operations could be materially adversely affected by competition.

## Employees

As of December 31, 2002, the Company had 94 employees, including 16 in finance and data processing, 6 in administration, 15 in exploration and development, 52 in production and 5 in natural gas marketing. The Company's engineers, supervisors and well tenders are generally responsible for the day-to-day operation of wells and pipeline systems. In addition, the Company retains subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites. The Company's employees act as supervisors of the subcontractors.

The Company's employees are not covered by a collective bargaining agreement. The Company considers relations with its employees to be excellent.



## Facilities

The Company owns and occupies three buildings in Bridgeport, West Virginia, two of which serve as the Company's headquarters and one which serves as a field operating site. The Company also owns a field operating building in Gilmer County, West Virginia. The Company leases field operating offices in Colorado, Michigan and Pennsylvania under operating leases. The Company believes that its current facilities are sufficient for its current and anticipated operations.

### Item 3. Legal Proceedings

From time to time the Company is a party to various legal proceedings in the ordinary course of business. The Company is not currently a party to any litigation that it believes would materially affect the Company's business, financial condition or results of operations.

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

No matters were submitted to a vote of security holders during the fourth quarter of the fiscal year covered by this report.

## PART II

### Item 5. Market for the Company's Common Stock and Related Stockholders Matters

The common stock of the Company is traded in the Nasdaq National Market under the symbol PETD. The following table sets forth, for the periods indicated, the high and low bid quotations per share of the Company's common stock in the over-the-counter market, as reported by Nasdaq. These quotations represent inter-dealer prices without retail markups, markdowns, commissions or other adjustments and may not represent actual transactions.

	<u>High</u>	<u>Low</u>
<u>2002</u>		
First Quarter	6.65	5.70
Second Quarter	6.66	5.86
Third Quarter	5.95	4.60
Fourth Quarter	5.70	4.75
<u>2001</u>		
First Quarter	7.94	5.72
Second Quarter	8.84	5.94
Third Quarter	6.47	4.38
Fourth Quarter	6.30	4.72

As of December 31, 2002, there were approximately 1,170 record holders of the Company's common stock.

The Company has not paid any dividends on its common stock and currently intends to retain earnings for use in its business. Therefore, it does not expect to declare cash dividends in the foreseeable future. Further, the Company's Credit Agreement restricts the payment of dividends.



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

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

Statements, other than historical facts, contained in this Annual Report on Form 10-K, including statements of estimated oil and gas production and reserves, drilling plans, future cash flows, anticipated capital expenditures and Management's strategies, plans and objectives, are "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes that its forward looking statements are based on reasonable assumptions, it cautions that such statements are subject to a wide range of risks and uncertainties incidental to the exploration for, acquisition, development and marketing of oil and gas, and it can give no assurance that its estimates and expectations will be realized. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to, changes in production volumes, worldwide demand, and commodity prices for petroleum natural resources; the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and gas reserves; risks incident to the drilling and operation of oil and gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; the effect of hedging activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-K.

Results of Operations

Year Ended December 31, 2002 Compared with December 31, 2001

Revenues. Total revenues for the year ended December 31, 2002 were \$135.3 million compared to \$177.1 million for the year ended December 31, 2001, a decrease of approximately \$41.8 million or 23.6%. Such decrease was primarily a result of reduced drilling revenues, gas marketing activities and oil and gas sales. Drilling revenues for the year ended December 31, 2002 were \$57.1 million compared to \$76.3 million for the year ended December 31, 2001, a decrease of approximately \$19.2 million or 25.2%. The decrease was a result of higher drilling activity carried over from the Company's public drilling programs at the end of 2000. The wells were drilled and completed during the first three quarters of 2001. The carryover resulted from a shortage of drilling rigs and field services during the second half of 2000 which delayed the drilling and completion of the wells which normally would have been drilled during the second half of 2000. Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's natural gas marketing subsidiary for the year ended December 31, 2002 was \$46.4 million compared to \$66.2 million for the year ended December 31, 2001, a decrease of approximately \$19.8 million or 29.9%. Such decrease was due to natural gas sold at significantly lower average sales prices along with slightly lower volumes sold. Oil and gas sales from the Company's producing properties for the year ended December 31, 2002 were \$22.9 million compared to \$25.9 million for the year ended December 31, 2001, a decrease of approximately \$3.0 million or 11.6%. Such decrease was due to lower average sales prices of natural gas offset in part by an increase in volumes produced and sold of natural gas and oil from the Company's producing properties. 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 market has remained prevalent in the last few years. Natural gas prices declined dramatically at the end of the fourth quarter of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter, Colorado prices began to increase, although they continue to trail prices in other areas by a greater than normal margin. The Company believes the low prices in the Rocky Mountain Region, including Colorado, result from increasing local supplies that exceed the local demand and pipeline capacity available to move gas from the region. In May of 2003, the Kern River Pipeline is scheduled to complete a capacity addition that will add about 900 million cubic feet of capacity for deliveries to Utah and southern California. This represents almost 30% of the current pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline will eliminate or reduce the local supply surplus, leading to improved prices in the region compared to other producing areas.

If the pipeline is not completed on schedule, the price of natural gas in the Rocky Mountains is likely to continue to be discounted compared to other areas. If this occurs, the Company's oil and gas sales in 2003 will be lower than they might otherwise be, and the sales of the Company's drilling programs, which focus on Colorado development, could be adversely impacted. Beginning in the second quarter and continuing later in the year, the Company entered into some commodity price hedging contracts for production from May 2002 through October 2003 to protect ourselves against possible short-term price weaknesses. Well operations and pipeline income for the year ended December 31, 2002 was \$6.1 million compared to \$5.6 million for the year ended December 31, 2001, an increase of approximately \$500,000 or 8.9%. Such increase was due to an increase in the number of wells and pipelines operated by the Company. Other income for the year ended December 31, 2002 was \$2.9 million compared to \$3.1 million for the year ended December 31, 2001, a decrease of approximately \$200,000 or 6.5%.

Costs and expenses. Costs and expenses for the year ended December 31, 2002 were \$122.3 million compared to \$156.0 million for the year ended December 31, 2001, a decrease of approximately \$33.7 million, or 21.6%. Oil and gas well drilling operations costs for the year ended December 31, 2002 were \$49.2 million compared to \$66.0 million for the year ended December 31, 2001, a decrease of approximately \$16.8 million or 25.5%. Such decrease was due to the reduced drilling activity referred to above. The costs of gas marketing activities of RNG for the year ended December 31, 2002 were \$46.2 million compared to \$65.7 million for the year ended December 31, 2001, a decrease of \$19.5 million or 29.7%. Such decrease was due to lower average prices of natural gas purchased for resale and slightly lower volumes purchased. Based on the nature of RNG's gas marketing activities, hedging did not have a significant impact on RNG's net margins from marketing activities during either period. Oil and gas production costs from the Company's producing properties for the year ended December 31, 2002 were \$9.1 million compared to \$8.6 million for the year ended December 31, 2001 an increase of approximately \$500,000 or 5.8%. Such increase was due to the increased sales volumes from the Company's oil and gas producing properties and increased number of wells operated by the Company. General and administrative expenses for the year ended December 31, 2002 were \$4.4 million compared to \$4.1 million for the year ended December 31, 2001, an increase of approximately \$300,000. Depreciation, depletion and amortization costs for the year ended December 31, 2002 were \$12.1 million compared to \$10.6 million for the year ended December 31, 2001, an increase of approximately \$1.5 million or 14.2%. Such increase was due to the increased amount of production and investment in oil and gas properties owned by the Company. Interest costs for the year ended December 31, 2002 were \$1.3 million compared to \$1.0 million for the year ended December 31, 2001 an increase of approximately \$300,000. Such increase was due to higher average debt balances offset in part by lower average interest rates.

Net income. Net income for the year ended December 31, 2002 was \$9.3 million compared to \$15.0 million for the year ended December 31, 2001, a decrease of approximately \$5.7 million or 38.0%.

#### Year Ended December 31, 2001 Compared with December 31, 2000

Revenues. Total revenues for the year ended December 31, 2001 were \$177.1 million compared to \$141.2 million for the year ended December 31, 2000, an increase of approximately \$35.9 million, or 25.4%. Drilling revenues for the year ended December 31, 2001 were \$76.3 million compared to \$43.2 for the year ended December 31, 2000, an increase of approximately \$33.1 million, or 76.6%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in the availability of drilling rigs which allowed us to reduce the drilling backlog from \$43.8 million as of December 31, 2000 to \$31.6 million as of December 31, 2001. Natural gas sales from the marketing activities of RNG for the year ended December 31, 2001 were \$66.2 million compared to \$71.4 million for the year ended December 31, 2000, a decrease of approximately \$5.2 million or 7.3%. Such decrease was due to decreased volumes of natural gas sold. Oil and gas sales from the Company's producing properties for the year ended December 31, 2001 were \$25.9 million compared to \$19.0 million for the year ended December 31, 2000, an increase of approximately \$6.9 million or 36.3%. Such increase was due to increased production of producing properties along with new wells drilled and higher average sales prices of natural gas offset in part by lower average oil sales prices from the Company's producing properties. 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 market has remained prevalent in the last few years. From late 1998 through the first quarter of 1999, we experienced a decline in energy commodity prices. However, in the summer of 2000 and continuing into 2001, prices improved. For the months of April, 2000 through October, 2001, we had certain natural gas hedges in place that prevented us from realizing the full impact of this price environment. Despite this limitation, our realized natural gas sales price for the year ended December 31, 2001 was \$3.53 per Mcf compared to \$2.74 for the year ended December

31, 2000. In the final months of 2000 and the first quarter of 2001, the NYMEX futures market reported unprecedented natural gas contract prices. During the year ended December 31, 2001, the hedging activities resulted in oil and gas sales being \$3.4 million lower than if the Company had not hedged. As of December 31, 2001, the Company had no hedges or option contracts in place for its oil and gas production. RNG in its normal course of business had natural gas hedges and option contracts as of December 31, 2001. However, based on its gas marketing activities, hedging and option contracts did not have a significant impact on RNG's net margins from gas marketing activities in 2001. Well operations and pipeline income for the year ended December 31, 2001 was \$5.6 million compared to \$5.1 million for the year ended December 31, 2000, an increase of approximately \$500,000 or 9.8%. Such increase resulted from an increase in the number of wells operated by the Company. Other income for the year ended December 31, 2001 was \$3.1 million compared to \$2.5 million for the year ended December 31, 2000, an increase of approximately \$600,000 or 24.0%. Such increase resulted from interest earned on higher average cash balances.

Costs and expenses. Costs and expenses for the year ended December 31, 2001 were \$156.0 million compared to \$126.9 million for the year ended December 31, 2000, an increase of approximately \$29.1 million, or 22.9%. Oil and gas well drilling operations costs for the year ended December 31, 2001 were \$66.0 million compared to \$35.2 million for the year ended December 31, 2000, an increase of approximately \$30.8 million or 87.5%. Such increase was due to the increased drilling activity referred to above. The costs of gas marketing activities of RNG for the year ended December 31, 2001 were \$65.7 million compared to \$71.6 million for the year ended December 31, 2000, a decrease of \$4.9 million or 6.8%. Such decrease was due to lower volumes of natural gas purchased for resale. Based on the nature of RNG's gas marketing activities, hedging and option contracts did not have a significant impact on RNG's net margins from marketing activities during 2001. Oil and gas production costs from the Company's producing properties for the year ended December 31, 2001 were \$8.6 million compared to \$8.3 million for the year ended December 31, 2000 an increase of approximately \$300,000 or 3.6%. General and administrative expenses for the year ended December 31, 2001 were \$4.1 million compared to \$3.6 million for the year ended December 31, 2000, an increase of approximately \$500,000. Depreciation, depletion and amortization costs for the year ended December 31, 2001 were \$10.6 million compared to \$6.9 million for the year ended December 31, 2000, an increase of approximately \$3.7 million or 53.6%. Such increase was due to the increased amount of production and investment in oil and gas properties owned by the Company. Interest costs for the year ended December 31, 2001 were \$1.0 million compared to \$1.2 million for the year ended December 31, 2000 a decrease of approximately \$200,000. Such decrease was due to lower average debt balances along with lower average interest rates.

Net income. Net income for the year ended December 31, 2001 was \$15.0 million compared to \$10.7 million for the year ended December 31, 2000, an increase of approximately \$4.3 million or 40.2%.

#### Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations, capital raised through drilling partnerships, and use of the Company's credit facility. Operational cash flow is generated by sales of natural gas from the Company's well interests, well drilling and operating activities for the Company's investor partners, natural gas gathering and transportation, and natural gas marketing. Cash payments from Company-sponsored partnerships are used to drill and complete wells for the partnerships, with operating cash flow accruing to the Company to the extent payments exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities.

Natural gas and oil prices have been unusually volatile for the past 24 months, and the Company 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 the remainder of the year with natural gas storage levels at five-year low levels. The Company believes this situation creates the possibility of both periods of low prices and continued high prices.

Earlier this year, our Colorado gas prices had been adversely effected by an increase in the negative “basis” between NYMEX and Colorado prices. Pipeline capacity from the area to major markets in California and the Midwest is not adequate to move the new supplies developed over the past several years by oil and gas companies when local demand is at low summer levels. The result has been lower prices and some limited curtailment of production during the summer months. This situation has corrected itself some this winter. Several major pipeline projects are underway and in planning stages that will improve capacity over the next several years. There remains a possibility of greater seasonal volatility in Colorado than some other producing areas, but we expect the situation to improve over the coming year.

Because of the uncertainty surrounding gas prices we used hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2003 we have in place a series of asymmetric costless collars. Under the collar arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. These floor and ceiling prices were set at levels which allowed us to set floors on two units of production for each unit of production with a ceiling. The positions in effect as of December 31, 2002 on the Company's share of production are shown in the following table:

Month	Floors		Ceilings	
	Monthly Quantity MMBtu	Contract Price	Monthly Quantity MMBtu	Contract Price
NYMEX Based Hedges				
Jan 2003	114,000	\$3.70	57,000	\$4.10
Jan 2003	114,000	\$3.80	57,000	\$4.40
Feb 2003	114,000	\$3.50	57,000	\$4.20
Feb 2003	114,000	\$3.60	57,000	\$4.30
Mar 2003	114,000	\$3.50	57,000	\$3.75
Mar 2003	114,000	\$3.45	57,000	\$4.20
Apr 2003	114,000	\$3.50	57,000	\$3.80
May 2003 - Oct 2003	114,000	\$3.40	57,000	\$3.80
Colorado Interstate Gas (CIG) Based Hedges				
Jan 2003-Mar 2003	20,000	\$2.75	10,000	\$4.45
Jan 2003-Mar 2003	29,000	\$2.75	6,500	\$3.28
Apr 2003-Oct 2003	32,000	\$2.50	8,000	\$3.13

The Company hedges prices for its partners' share of production as well as its own production. Actual wellhead prices will vary based on local contract conditions, gathering and other costs and factors.

Oil prices have strengthened from earlier in the year. While oil prices are influenced by supply and demand, global geopolitics may be the single most important determinant. Since the percentage of company production reflected by oil sales has increased to almost 18% for 2002, variations in oil prices will have a greater impact on the Company than in the past.

The Company plans to conduct most, if not all, of its 2003 drilling operations in Colorado. If the planned pipeline capacity increases do not occur, it could reduce the Company's results from its producing activities. It could also make the company's drilling programs less attractive to potential investors. However, the Rocky Mountain region is the only onshore area of the U.S. with increasing production. The Company believes the necessary pipelines will be constructed, so increasing Rocky Mountain gas can move to the markets where it will be needed.

The Company closed four public drilling partnerships during 2002. The total amount received during 2002 was \$56.9 million compared to \$57.1 million for 2001. The Company closed its fourth program of 2002 on December 31, 2002 in the amount of \$29.1 million and will drill the wells during the first quarter 2003. The Company invests, as its equity contribution to each drilling partnership, an additional sum approximating 20% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may tender their partnership units for repurchase at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are tendered, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if tendered by the investors, is currently approximately \$1,878,200. The Company has adequate liquidity to meet this obligation.

The Company has a credit facility with Bank One, NA and BNP Paribas of \$100 million subject to adequate oil and natural gas reserves. The current borrowing base is \$58.0 million, of which the Company has activated \$40.0 million of the facility. As of December 31, 2002, the outstanding balance on the line of credit was \$25.0 million of which \$10 million was subject to an interest rate swap at a rate of 8.39%, \$6.0 million subject to a 90-day LIBOR (London Interbank Market Rate) of 3.27% and the remaining \$9.0 million was subject to prime rate of 4.25%. The line of credit is at prime, with LIBOR alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2005.

The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and costs efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

A summary of Company's contractual obligations and due dates are as follows:

Contractual Obligations	<u>Total</u>	Payments due by period			
		<u>Less than 1 year</u>	<u>1-3 years</u>	<u>3-5 years</u>	<u>More than 5 years</u>
Long-Term Debt	\$25,000,000	-	\$25,000,000	-	-
Operating Leases	\$1,547,600	\$979,300	\$518,100	\$50,200	-
Other Liabilities	\$4,137,200	-	917,700	120,000	\$3,099,500
Total	<u>\$30,684,800</u>	<u>\$979,300</u>	<u>\$26,435,800</u>	<u>\$170,200</u>	<u>\$3,099,500</u>

#### Critical Accounting Policies

Certain accounting policies are very important to the portrayal of Company's financial condition and results of operations and require management's most subjective or complex judgments. The policies are as follows:

##### Revenue Recognition

Oil and gas wells are drilled primarily on a contract basis. The Company follows the percentage-of-completion method of income recognition for drilling operations in progress.

Sales of natural gas are recognized when sold, oil revenues are recognized when produced into a stock tank.

Well operations income consists of operation charges for well upkeep, maintenance and operating lease income on tangible well equipment.

## Valuation of Accounts Receivable

Management reviews accounts receivable to determine which are doubtful of collection. In making the determination of the appropriate allowance for doubtful accounts, management considers Company's history of write-offs, relationships and overall credit worthiness of its customers, and well production data for receivables related to well operations.

## Impairment of Long-Lived Assets

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

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flow, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Unproved properties are assessed on a property-by-property basis and properties considered to be impaired are charged to expense when such impairment is deemed to have occurred.

## Deferred Tax Asset Valuation Allowance

Deferred tax assets are recognized for deductible temporary differences, net operating loss carryforwards, and credit carryforwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset cannot be recognized under the preceding criteria, a valuation allowance has been established.

The judgments used in applying the above policies are based on management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates. See additional discussions in this Management's Discussion and Analysis.

## New Accounting Standards

In June 2001, the FASB issued SFAS 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The Company also records a corresponding asset which is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Company is required to adopt SFAS No. 143 on January 1, 2003. At this time the Company does not believe that the adoption of this statement will have a material effect on its financial position, results or operation, cash flows or disclosures.

In December 2002, the FASB issued SFAS 148, Accounting for Stock-Based Compensation - Transition and Disclosure, an amendment of FASB Statement No. 123. This statement amends SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending December 31, 2002 and are included in the notes to these financial statements.



## Item 7A. Quantitative and Qualitative Disclosure About Market Risk.

### Market-Sensitive Instruments and Risk Management

The Company's primary market risk exposures are interest rate risk and commodity price risk. These exposures are discussed in detail below:

#### Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of December 31, 2002 is \$59,241,500 with an average interest rate of 0.78%. As of December 31, 2002, the Company has long-term debt of \$25,000,000 of which \$10,000,000 is subject to an interest rate swap at a rate of 8.39%, \$6,000,000 subject to a 90-day LIBOR rate of 3.27% and \$9,000,000 was subject to a prime rate of 4.25%.

#### Commodity Price Risk

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production and CIG-based contracts traded by Bank One for Colorado production. These hedging arrangements have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the hedge relates and, in the case of RNG, the cost of gas supplies purchased for marketing activities. As a result, while these hedging arrangements are structured to reduce the Company's exposure to changes in price associated with the hedged commodity, they also limit the benefit the Company might otherwise have received from price changes associated with the hedged commodity. The Company's policy prohibits the use of natural gas future and option contracts for speculative purposes.

As of December 31, 2002 RNG had entered into a series of natural gas future contracts stemming from its marketing activities. Open future contracts maturing in 2003 are for the sale of 3,210,000 mmbtu of natural gas with a weighted average price of \$3.97 mmbtu resulting in a total contract amount of \$12,728,100 and a fair market value of \$(1,912,200) and for the purchase of 740,000 mmbtu of natural gas with a weighted average price of \$4.15 mmbtu resulting in a total contract amount of \$3,073,200 and a fair market value of \$480,800. There were no open option contracts stemming from RNG's marketing activities as of December 31, 2002. As of December 31, 2001, RNG had entered into a series of natural gas future contracts and option contracts stemming from its marketing activities. Open future contracts matured in 2002 were for the sale of 1,680,000 mmbtu of natural gas with a weighted average price of \$3.18 mmbtu resulting in a total contract amount of \$5,343,500 and a fair market value of \$479,300. Open option contracts matured in 2002 were for the sale of 20,000 mmbtu with a weighted average floor price of \$2.85 mmbtu and a fair value of \$9,000.

As of December 31, 2002, PDC had entered into a series of natural gas future contracts and option contracts stemming from its natural gas production. Open future contracts maturing in 2003 are for the sale of 280,000 mmbtu of natural gas with a weighted average price of \$4.25 mmbtu resulting in a total contract amount of \$1,190,000 and a fair market value of \$(209,700). Open option contracts maturing in 2003 are for the sale of 2,155,600 mmbtu with a weighted average floor price of \$3.15 mmbtu and a fair value of \$105,600 and 794,800 mmbtu with a weighted average ceiling price of \$3.80 mmbtu and a fair value of \$(442,800). As of December 31, 2001, PDC had no natural gas future contracts or option contracts stemming from its natural gas production.

The average NYMEX closing price for natural gas for the years 2002, 2001 and 2000 was \$3.22 mmbtu, \$4.27 mmbtu, and \$3.88 mmbtu. The average NYMEX closing price for oil for the years 2002, 2001 and 2000 was \$26.98 bbl, \$26.60 bbl and \$30.95 bbl. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

## Disclosure of Limitations

As the information above incorporates only those exposures that exist at December 31, 2002, it does not consider those exposures or positions which could arise after that date. As a result, the Company's ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, the Company's hedging strategies at the time, and interest rates 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 10. Directors and Executive Officers of the Company

##### Directors and Executive Officers of the Company

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

Name	Age	Positions and Offices Held	Held Current Position Since
James N. Ryan	71	Chairman, Chief Executive Officer and Director	November 1983
Steven R. Williams	51	President and Director	March 1983
Dale G. Rettinger	58	Chief Financial Officer, Executive Vice President, Treasurer and Director	July 1980
Roger J. Morgan	75	Secretary	November 1969
Vincent F. D'Annunzio	50	Director	February 1989
Jeffrey C. Swoveland	47	Director	March 1991
Donald B. Nestor	54	Director	March 2000
Kimberly Luff Wakim	44	Director	January 2003

James N. Ryan has served as President and Director of PDC from 1969 to 1983 and was elected Chairman and Chief Executive Officer in March 1983.

Steven R. Williams has served as President and Director of PDC since March 1983. Prior to joining PDC, Mr. Williams was employed by Exxon until 1979 and attended Stanford Graduate School of Business, graduating in 1981. He then worked with Texas Oil and Gas until July 1982, when he joined Exco Enterprises, an oil and gas investment company as manager of operations.

Dale G. Rettinger has served as Vice President and Treasurer of PDC since July 1980, and was appointed Chief Financial Officer in September 1997. Mr. Rettinger was elected Director in 1985. Previously Mr. Rettinger was a partner with Main Hurdman, Certified Public Accountants, having served in that capacity since 1976.

Roger J. Morgan has been a member of the law firm of Young, Morgan & Cann, Clarksburg, West Virginia since 1955. Mr. Morgan is not active in the day-to-day business of PDC, but his law firm provides legal services to PDC.

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

Jeffrey C. Swoveland has served as Chief Financial Officer of Body Media since September, 2000. Prior thereto, Mr. Swoveland was Vice President-Finance and Treasurer of Equitable Resources Inc since 1994.

Donald B. Nestor, elected as a director in March, 2000, is a Certified Public Accountant and a Partner in the CPA firm of Toothman Rice, P.L.L.C. and is in charge of the firm's Buckhannon, West Virginia office. Mr. Nestor has served in that capacity since 1975.

Kimberly Luff Wakim, elected director in January 2003, an Attorney and Certified Public Accountant, is a Partner with the law firm Thorp, Reed & Armstrong LLP. Ms. Wakim joined Thorp Reed & Armstrong LLP in 1990.

The Company's By-Laws provide that the directors of the Company shall be divided into three classes and that, at each annual meeting of stockholders of the Company, successors to the class of directors whose term expires at the annual meeting will be elected for a three-year term. The classes are staggered so that the term of one class expires each year. Mr. Williams, Mr. Nestor and Ms. Wakim are members of the class whose term expires in 2003; Mr. Ryan and Mr. D'Annunzio are members of the class whose term expires in 2004; and Mr. Rettinger and Mr. Swoveland are members of the class whose term expires in 2005. There is no family relationship between any director or executive officer and any other director or executive officer of the Company. There are no arrangements or understandings between any director or officer and any other person pursuant to which such person was selected as an officer.

On January 24, 2003, the Company adopted a Code of Business Conduct and Ethics Policy meeting the specified standards applicable to the Chief Executive Officer and Chief Financial Officer. The policy also covers all the corporate officers.

The Audit Committee of the Board of Directors is comprised entirely of independent outside directors. Donald B. Nestor, CPA, a partner in the certified public accounting firm of Toothman Rice PLLC, chairs the committee. Mr. Nestor and the other audit committee members, qualify as audit committee financial experts and are independent of management.

#### Item 11. Executive Compensation

There is incorporated by reference herein in response to this Item the material under the heading "Election of Directors - Remuneration of Directors and Officers", "Election of Directors - Stock Options" and "Election of Directors - Interest of Management in Certain Transactions" in the Company's definitive proxy statement for its 2003 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2003.

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

There is incorporated by reference herein in response to this Item, the material under the heading "Election of Directors", in the Company's definitive proxy statement for its 2003 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2003.

The Company has the following common stock options outstanding under the stock option plans approved by the stockholders:

Equity Compensation Plan Information December 31, 2002			
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	1,160,000 shares	\$4.48	-
Equity compensation plans not approved by security holders	-	-	-
Total	1,160,000 shares	\$4.48	-

Item 13. Certain Relationships and Related Transactions

The response to this item is set forth herein in Note 8 in the Notes to Consolidated Financial Statements and under "Election of Directors - Interest of Management in Certain Transactions," in the Company's definitive proxy statement for its 2003 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2003.

Item 14. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, the Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Exchange Act Rule 13a-14(c)) within 90 days of the filing date of this annual report, 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 Company'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 subsequent to the date of their evaluation.

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

(a) (1) Financial Statements:

See Index to Financial Statements and Schedules on page F-1.

(2) Financial Statement Schedules:

See Index to Financial Statements and Schedules on page F-1.

Schedules and Financial Statements Omitted

All other 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:

See Exhibits Index on page E-1.

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.

PETROLEUM DEVELOPMENT CORPORATION

By /s/ James N. Ryan  
James N. Ryan, Chairman

March 7, 2003

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/ James N. Ryan</u> James N. Ryan	Chairman, Chief Executive Officer and Director	March 7, 2003
<u>/s/ Steven R. Williams</u> Steven R. Williams	President and Director	March 7, 2003
<u>/s/ Dale G. Rettinger</u> Dale G. Rettinger	Chief Financial Officer Executive Vice President, Treasurer and Director (principal financial and accounting officer)	March 7, 2003
<u>/s/ Vincent F. D'Annunzio</u> Vincent F. D'Annunzio	Director	March 7, 2003

## FORM 10-K CERTIFICATION

I, James N. Ryan, certify that:

1. I have reviewed this annual report on Form 10-K of Petroleum Development Corporation;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report.
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
  - (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
  - (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
  - (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
  - (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
  - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 7, 2003

/s/ James N. Ryan  
James N. Ryan  
Chief Executive Officer  
of Petroleum Development Corporation

## FORM 10-K CERTIFICATION

I, Dale G. Rettinger, certify that:

1. I have reviewed this annual report on Form 10-K of Petroleum Development Corporation;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report.
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
  - (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
  - (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
  - (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
  - (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
  - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 7, 2003

/s/ Dale G. Rettinger  
Dale G. Rettinger  
Chief Financial Officer  
of Petroleum Development Corporation

## Exhibits Index

Exhibit Name	Exhibit Number	
Articles of Incorporation	3.1	Incorporated by reference to Form S-2 filed September 25, 1997
By Laws	3.2	Incorporated by reference to Form 8-K filed on January 24, 2003
Credit Agreement	10.1	
Employment Agreement - Steven R. Williams	10.2	
Employment Agreement - Dale G. Rettinger	10.3	
Code of Business Conduct and Ethics	14	
Certification by Chief Executive Officer	99.1	
Certification by Chief Financial Officer	99.2	



PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

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## Independent Auditors' Report

The Stockholders and Board of Directors  
Petroleum Development Corporation:

We have audited the consolidated financial statements of Petroleum Development Corporation and subsidiaries as listed in the accompanying index. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule as listed in the accompanying index. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule 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 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in note 13 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in 2001.

KPMG LLP

Pittsburgh, Pennsylvania  
February 25, 2003

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2002 and 2001

<u>Assets</u>	<u>2002</u>	<u>2001</u>
Current assets:		
Cash and cash equivalents	\$ 48,263,000	47,892,300
Restricted cash	2,760,500	283,300
Notes and accounts receivable	15,336,500	10,752,600
Inventories	1,174,100	1,117,900
Prepaid expenses	<u>4,125,300</u>	<u>4,659,300</u>
Total current assets	71,659,400	64,705,400
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	183,614,200	167,244,600
Pipelines	7,015,000	6,501,500
Transportation and other equipment	3,174,200	3,201,500
Land and buildings	<u>1,455,400</u>	<u>1,402,400</u>
	195,258,800	178,350,000
Less accumulated depreciation, depletion and amortization	<u>57,143,700</u>	<u>45,809,500</u>
	138,115,100	132,540,500
Other assets	<u>2,477,100</u>	<u>2,606,200</u>
	<u>\$212,251,600</u>	<u>199,852,100</u>

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2002 and 2001

	<u>2002</u>	<u>2001</u>
<u>Liabilities and Stockholders' Equity</u>		
Current liabilities:		
Accounts payable	\$ 17,425,500	17,118,600
Other accrued expenses	11,261,700	7,924,200
Advances for future drilling contracts	37,283,800	31,592,200
Funds held for future distribution	<u>3,917,900</u>	<u>4,650,800</u>
Total current liabilities	69,888,900	61,285,800
Long-term debt	25,000,000	28,000,000
Other liabilities	4,137,200	4,082,700
Deferred income taxes	12,103,300	9,710,800
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value \$.01 per share; authorized 50,000,000 shares; issued and outstanding 15,734,767 and 16,245,752 shares	157,300	162,400
Additional paid-in capital	29,316,800	32,922,500
Retained earnings	73,430,100	64,145,300
Accumulated other comprehensive loss, net of tax	<u>(1,782,000)</u>	<u>(457,400)</u>
Total stockholders' equity	<u>101,122,200</u>	<u>96,772,800</u>
	<u>\$212,251,600</u>	<u>199,852,100</u>

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Income

Years Ended December 31, 2002, 2001 and 2000

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Revenues:			
Oil and gas well drilling operations	\$57,149,100	76,291,200	43,194,700
Gas sales from marketing activities	46,365,900	66,207,400	71,402,400
Oil and gas sales	22,857,100	25,887,900	19,017,300
Well operations and pipeline income	6,116,200	5,604,200	5,061,600
Other income	<u>2,853,600</u>	<u>3,132,400</u>	<u>2,540,500</u>
	135,341,900	177,123,100	141,216,500
Costs and expenses:			
Cost of oil and gas well drilling operations	49,166,200	65,999,900	35,244,300
Cost of gas marketing activities	46,184,300	65,740,300	71,648,500
Oil and gas production costs	9,074,200	8,582,700	8,303,600
General and administrative expenses	4,391,900	4,145,700	3,616,900
Depreciation, depletion and amortization	12,103,300	10,578,300	6,943,500
Interest	<u>1,339,800</u>	<u>993,400</u>	<u>1,186,000</u>
	<u>122,259,700</u>	<u>156,040,300</u>	<u>126,942,800</u>
Income before income taxes	13,082,200	21,082,800	14,273,700
Income taxes	<u>3,797,400</u>	<u>6,115,000</u>	<u>3,592,700</u>
Net income	<u>\$ 9,284,800</u>	<u>14,967,800</u>	<u>10,681,000</u>
Basic earnings per common share	<u>\$.59</u>	<u>.92</u>	<u>.66</u>
Diluted earnings per common and common equivalent share	<u>\$.58</u>	<u>.90</u>	<u>.65</u>

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 2002, 2001 and 2000

	<u>Common stock issued</u>		Additional Paid-in- capital	Retained Earnings	Accumulated Other Comprehensive Income	<u>Total</u>
	Number Of Shares	Amount				
Balance, December 31, 1999	15,737,795	\$157,400	32,071,000	38,496,500	-	70,724,900
Issuance of common stock:						
Exercise of employee stock options	511,584	5,100	511,700	-	-	516,800
Purchase of properties	100,000	1,000	549,000	-	-	550,000
Amortization of stock award	-	-	5,500	-	-	5,500
Repurchase and cancellation of treasury stock	(105,335)	(1,100)	(420,100)	-	-	(421,200)
Income tax benefit from the exercise of stock options	-	-	199,900	-	-	199,900
Net income	-	-	-	10,681,000	-	10,681,000
Balance, December 31, 2000	<u>16,244,044</u>	<u>\$162,400</u>	<u>32,917,000</u>	<u>49,177,500</u>	<u>-</u>	<u>82,256,900</u>
Issuance of common stock	1,708	-	-	-	-	-
Amortization of stock award	-	-	5,500	-	-	5,500
Net income	-	-	-	14,967,800	-	14,967,800
Comprehensive income:						
Cumulative effect of change in accounting principle – January 1, 2001 (net of tax of \$8,052,700)	-	-	-	-	(12,079,100)	-
Reclassification adjustment for settlement of contracts Included in net income (net of tax of \$3,046,900)	-	-	-	-	4,971,200	-
Changes in fair value of outstanding hedging positions (net of tax of \$4,076,100)	-	-	-	-	<u>6,650,500</u>	-
Other comprehensive loss	-	-	-	-	(457,400)	<u>(457,400)</u>
Comprehensive income	-	-	-	-	-	<u>14,510,400</u>
Balance, December 31, 2001	16,245,752	\$ 162,400	32,922,500	64,145,300	(457,400)	96,772,800
Issuance of common stock:						
Exercise of employee stock options	70,000	700	78,100	-	-	78,800
Amortization of stock award	-	-	5,500	-	-	5,500
Repurchase and cancellation of treasury stock	(580,985)	(5,800)	(3,689,300)	-	-	(3,695,100)
Net income	-	-	-	9,284,800	-	9,284,800
Comprehensive income:						
Reclassification adjustment for settlement of contracts Included in net income (net of tax of \$9,100)	-	-	-	-	14,800	-
Changes in fair value of outstanding hedging positions and interest rate swap (net of tax of \$820,900)	-	-	-	-	<u>(1,339,400)</u>	-
Other comprehensive loss	-	-	-	-	(1,324,600)	<u>(1,324,600)</u>
Comprehensive income	-	-	-	-	-	<u>7,960,200</u>
Balance, December 31, 2002	<u>15,734,767</u>	<u>\$ 157,300</u>	<u>29,316,800</u>	<u>73,430,100</u>	<u>(1,782,000)</u>	<u>101,122,200</u>

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years Ended December 31, 2002, 2001 and 2000

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Cash flows from operating activities:			
Net income	\$9,284,800	14,967,800	10,681,000
Adjustment to net income to reconcile to cash provided by operating activities:			
Deferred income taxes	2,986,400	4,002,300	1,838,300
Depreciation, depletion and amortization	12,103,300	10,578,300	6,943,500
Gain from sale of assets	(25,800)	(132,400)	(199,200)
Expired and abandoned leases	1,129,400	919,200	672,700
Amortization of stock award	5,500	5,500	5,500
(Increase) decrease in notes and accounts receivable	(4,583,900)	12,895,400	(13,384,800)
Increase in inventories	(56,200)	(20,000)	(520,300)
Decrease (increase) in prepaid expenses	369,200	3,243,900	(4,774,700)
Decrease (increase) in other assets	56,300	336,700	(375,700)
Increase (decrease) in accounts payable and accrued expenses	1,945,200	(8,219,900)	15,359,700
Increase (decrease) in advances for future drilling contracts	5,691,600	(12,217,200)	18,672,000
(Decrease) increase funds held for future distribution	<u>(732,900)</u>	<u>2,210,700</u>	<u>412,500</u>
Total adjustments	<u>18,888,100</u>	<u>13,602,500</u>	<u>24,649,500</u>
Net cash provided by operating activities	<u>28,172,900</u>	<u>28,570,300</u>	<u>35,330,500</u>
Cash flows from investing activities:			
Capital expenditures	(19,777,000)	(42,661,100)	(27,932,100)
Proceeds from sale of leases	1,042,500	4,732,200	1,588,700
Proceeds from sale of fixed assets	25,800	12,200	680,100
(Increase) decrease in restricted cash	<u>(2,477,200)</u>	<u>2,655,000</u>	<u>(2,324,000)</u>
Net cash used in investing activities	<u>(21,185,900)</u>	<u>(35,261,700)</u>	<u>(27,987,300)</u>
Cash flows from financing activities:			
Proceeds from/(retirement of) debt, net	(3,000,000)	10,650,000	8,050,000
Proceeds from issuance of stock	78,800	-	95,600
Repurchase and cancellation of treasury stock	<u>(3,695,100)</u>	<u>-</u>	<u>-</u>
Net cash (used in) provided by financing activities	<u>(6,616,300)</u>	<u>10,650,000</u>	<u>8,145,600</u>
Net increase in cash and cash equivalents	370,700	3,958,600	15,488,800
Cash and cash equivalents, beginning of year	<u>47,892,300</u>	<u>43,933,700</u>	<u>28,444,900</u>
Cash and cash equivalents, end of year	<u>\$48,263,000</u>	<u>47,892,300</u>	<u>43,933,700</u>

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

Years Ended December 31, 2002, 2001 and 2000

(1) Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Petroleum Development Corporation and its wholly owned subsidiaries. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in limited partnerships under the proportionate consolidation method. Under this method, the Company's financial statements include its prorata share of assets and liabilities and revenues and expenses, respectively, of the limited partnerships in which it participates.

The Company is involved in three business segments. The segments are drilling and development, natural gas sales and well operations. (See Note 19)

The Company grants credit to purchasers of oil and gas and the owners of managed properties, substantially all of whom are located in West Virginia, Tennessee, Pennsylvania, Ohio, Michigan, North Dakota and Colorado.

Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

Inventories

Inventories of well equipment, parts and supplies are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased in excess of deliveries to customers and is recorded at the lower of cost or market. An inventory of oil located in stock tanks on well locations, is carried at market at the end of each period.

Oil and Gas Properties

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

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flow, 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.

(Continued)



Notes to Consolidated Financial Statements

Unproved properties are assessed on a property-by-property basis and properties considered to be impaired are charged to expense when such impairment is deemed to have occurred.

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 units of depreciable or depletable property, the net cost thereof, less proceeds or salvage value, is credited or charged to income. Upon retirement of a partial unit of property, the cost thereof is charged to accumulated depreciation and depletion.

Based on the Company's experience, management believes site restoration, dismantlement and abandonment costs net of salvage to be immaterial in relation to operating costs. These costs are being expensed when incurred.

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. SFAS No. 144 provides a single accounting model for long-lived assets to be disposed of. The Company adopted SFAS No. 144 on January 1, 2002. The adoption of SFAS No. 144 did not affect the Company's financial statements.

In accordance with SFAS No. 144, long-lived assets, such as property, plant, and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Prior to the adoption of SFAS No. 144, the Company accounted for long-lived assets in accordance with SFAS No. 121, *Accounting for Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of*.

Maintenance and repairs are charged to expense as incurred. Major renewals and betterments are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion and amortization are removed from the accounts, the proceeds applied thereto and any resulting gain or loss is reflected in income.

Buildings

Buildings are carried at cost and depreciated on the straight-line method over estimated useful lives of 30 years.

Advances for Future Drilling Contracts

Represents funds received from Partnerships and other joint ventures for drilling activities which have not been completed and accordingly have not yet been recognized as income in accordance with the Company's income recognition policies.

Retirement Plans

The Company has a 401-K contributory retirement plan (401-K Plan) covering full-time employees. The Company provides a discretionary matching of employee contributions to the plan.

The Company also has a profit sharing plan covering full-time employees. The Company's contributions to this plan are discretionary.

(Continued)

# PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

## Notes to Consolidated Financial Statements

The Company has a deferred compensation arrangement covering executive officers of the Company as a supplemental retirement benefit.

The Company has established split-dollar life insurance arrangements with certain executive officers. Under these arrangements, advances are made to these officers equal to the premiums due. The advances are collateralized by the cash surrender value of the policies. The Company records as other assets its share of the cash surrender value of the policies.

### Revenue Recognition

Oil and gas wells are drilled primarily on a contract basis. The Company follows the percentage-of-completion method of income recognition for drilling operations in progress.

Sales of natural gas are recognized when sold, oil revenues are recognized when produced into a stock tank.

Well operations income consists of operation charges for well upkeep, maintenance and operating lease income on tangible well equipment.

### Income Taxes

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

### Derivative Financial Instruments

All derivatives are recognized on the consolidated balance sheet at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as either a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability ("Cash flow" hedge), or a non-hedging derivative. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash-flow hedges to specific firm commitments or forecasted transactions. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, the Company discontinues hedge accounting prospectively. No hedging activities were discontinued during 2002 or 2001.

Changes in fair value of a derivative that is highly effective and that is designated and qualifies as a cash-flow hedge are recorded in other comprehensive income, until earnings are affected by the variability in cash flows of the designated hedged item. Changes in the fair value of non-hedging derivatives are reported in current-period earnings. The Company discontinues hedge accounting prospectively when it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item, the derivative expires or is sold, terminated, or exercised. Additionally, if the derivative is dedesignated as a hedging instrument, because it is unlikely that a forecasted transaction will occur, a hedged firm commitment no longer meets the definition of a firm commitment, or management determines that designation of the derivative as a hedging instrument is no longer appropriate, hedge accounting will discontinue.

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

For the year ended December 31, 2000, prior to adoption of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Certain Hedging Activities" and SFAS No. 138, "Accounting for Certain Hedging Activities", gains and losses related to qualifying hedges of firm commitments or anticipated transactions through the use of natural gas futures and option contracts were deferred and recognized in income or as adjustments of carrying amounts when the underlying hedged transaction occurred. In order for futures contracts to qualify as a hedge, there must be sufficient correlation to the underlying hedged transaction. The change in the fair value of derivative instruments which do not qualify for hedging were recognized into income in 2000

During 2000, the Company entered into an interest rate swap agreement which expires October 11, 2004 to reduce its exposure to market risks from changing interest rates. The interest rate differential to be paid or received was accrued and recognized as interest expense in the period incurred.

Stock Compensation

The Company has adopted SFAS No. 123, "Accounting for Stock-Based Compensation," which permits entities to recognize as expense over the vesting period the fair value of all stock-based awards on the date of grant. Alternatively, SFAS 123 allows entities to continue to measure compensation cost for stock-based awards using the intrinsic value based method of accounting prescribed by APB Opinion No. 25, "Accounting for Stock Issued to Employees," and to provide pro forma net income and pro forma earnings per share disclosures as if the fair value based method defined in SFAS 123 had been applied. The Company has elected to continue to apply the provisions of APB 25 and provide the pro forma disclosure provisions of SFAS 123. For stock options granted, the option price was not less than the market value of shares on the grant date, therefore, no compensation cost has been recognized. Had compensation cost been determined under the provisions of SFAS 123, the Company's net income and earnings per share would have been the following on a pro forma basis:

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Net income, as reported	\$9,284,800	\$14,967,800	\$10,681,000
Deduct total stock-based employee compensation expense determined under fair-value-based method for all rewards, net of tax	<u>-</u>	<u>(486,100)</u>	<u>(334,300)</u>
Pro forma net income	<u>\$9,284,800</u>	<u>\$14,481,700</u>	<u>\$10,346,700</u>
Pro forma basic earnings per share	<u>\$0.59</u>	<u>\$0.89</u>	<u>\$0.64</u>
Pro forma diluted earnings per share	<u>\$0.58</u>	<u>\$0.87</u>	<u>\$0.63</u>

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with generally accepted accounting principles. Actual results could differ from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and debt obligations are estimated to be substantially the same as the fair values as of December 31, 2002, 2001 and 2000.

# PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

## Notes to Consolidated Financial Statements

### New Accounting Standards

In June 2001, the FASB issued SFAS 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The Company also records a corresponding asset which is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Company is required to adopt SFAS No. 143 on January 1, 2003. At this time, the Company cannot reasonably estimate the effect of the adoption of this Statement on either its financial position, results of operations, or cash flows.

In December 2002, the FASB issued SFAS 148, Accounting for Stock-Based Compensation - Transition and Disclosure, an amendment of FASB Statement No. 123. This statement amends SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending December 31, 2002 and are included in the notes to these financial statements.

### (2) Notes and Accounts Receivable

Included in other assets are noncurrent accounts receivable as of December 31, 2002 and 2001, in the amounts of \$445,600 and \$173,600 net of an allowance for doubtful accounts of \$445,600 and \$174,600, respectively.

The allowance for doubtful current accounts receivable as of December 31, 2002 and 2001 was \$49,400 and \$349,900, respectively.

### (3) Long-Term Debt

On July 3, 2002 the Company executed a \$100 million credit facility with Bank One, NA and BNP Paribas. The agreement provides for borrowing up to \$100 million subject to and secured by adequate levels of oil and gas reserves. The current total borrowing base is \$58.0 million of which the Company has activated \$40 million of the facility. The Company is required to pay a commitment fee of 1/4 percent on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2005.

As of December 31, 2002 and 2001 the outstanding balance was \$25,000,000 and \$28,000,000, respectively. Any amounts outstanding under the credit facility are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends. As of December 31, 2002 and 2001 the Company was in compliance with all financial covenants in the credit agreement.

At December 31, 2002, \$10,000,000 of the outstanding balance was subject to an interest rate swap at a rate of 8.39%, \$6,000,000 was subject to a 90-day LIBOR rate of 3.27% and \$9,000,000 was subject to a prime rate of 4.25%.

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(4) Income Taxes

The Company's provision for income taxes consisted of the following:

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Current:			
Federal	\$604,200	1,639,300	1,182,000
State	<u>206,800</u>	<u>473,300</u>	<u>572,400</u>
Total current income taxes	<u>811,000</u>	<u>2,112,600</u>	<u>1,754,400</u>
Deferred:			
Federal	2,461,200	3,898,600	1,415,600
State	<u>525,200</u>	<u>103,800</u>	<u>422,700</u>
Total deferred income taxes	<u>2,986,400</u>	<u>4,002,400</u>	<u>1,838,300</u>
Total income taxes	<u>\$3,797,400</u>	<u>6,115,000</u>	<u>3,592,700</u>

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 34 percent to pretax income as a result of the following:

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Computed "expected" tax	\$4,447,900	7,168,200	4,853,100
State income tax	483,100	380,900	656,800
Percentage depletion	(680,000)	(935,000)	(758,300)
Nonconventional source fuel credit	(491,500)	(1,184,700)	(1,067,500)
Effect of state rate change	-	556,500	-
Other	<u>37,900</u>	<u>129,100</u>	<u>(91,400)</u>
	<u>\$3,797,400</u>	<u>6,115,000</u>	<u>3,592,700</u>

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2002 and 2001 are presented below:

	<u>2002</u>	<u>2001</u>
Deferred tax assets:		
Allowance for doubtful accounts	\$ 199,300	199,300
Drilling notes	84,500	88,100
Alternative minimum tax credit carryforwards (Section 29)	2,055,500	1,715,800
Future abandonment	505,900	409,300
Deferred compensation	2,000,400	2,100,500
Other	<u>40,600</u>	<u>48,900</u>
Total gross deferred tax assets	4,886,200	4,561,900
Less valuation allowance	-	-
Deferred tax assets	4,886,200	4,561,900
Less current deferred tax assets (included in prepaid expenses)	<u>(1,351,200)</u>	<u>(1,133,400)</u>
Net non-current deferred tax assets	3,535,000	3,428,500
Deferred tax liabilities:		
Properties and equipment, principally due to differences in		
Depreciation and amortization	<u>(16,730,500)</u>	<u>(13,419,800)</u>
Total gross deferred tax liabilities	<u>(16,730,500)</u>	<u>(13,419,800)</u>
Net deferred tax liability	<u>(13,195,500)</u>	<u>(9,991,300)</u>
Deferred income tax assets related to AOCI	<u>1,092,200</u>	<u>280,500</u>
Net deferred tax liability after AOCI	<u>\$(12,103,300)</u>	<u>(9,710,800)</u>

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

At December 31, 2002, the Company has alternative minimum tax credit carryforwards (Section 29) of approximately \$2,055,500 which are available to reduce future federal regular income taxes over an indefinite period.

Accumulated other comprehensive loss is net of tax of \$1,092,200, \$280,500 and \$0 as of December 31, 2002, 2001 and 2000, respectively. The income tax benefit from the exercise of stock options recorded in additional paid-in capital was \$0 in 2002 and 2001 and \$199,900 in 2000.

(5) Common Stock

Options

Options amounting to 185,000 and 180,000 shares were granted during 2001 and 2000, respectively, to certain employees and directors under the Company's Stock Option Plans. These options were granted with an exercise price equal to market value as of the date of grant and vest over a six month period. The outstanding options expire from 2005 to 2011.

The estimated fair value of the options granted during 2001 and 2000 was \$3.70 and \$2.48 per option, respectively. The fair value was estimated using the Black-Scholes option pricing model with the following assumptions for the 2001 and 2000 grant, respectively: risk-free interest rate of 5.88% and 6.13%, expected dividend yield of 0%, expected volatility of 50.23% and 57.31% and expected life of 7 years.

	<u>Number of Shares</u>	<u>Average Exercise Price</u>	<u>Range of Exercise Prices</u>
Outstanding December 31, 1999	<u>1,388,984</u>	<u>\$2.87</u>	<u>.94 - 6.13</u>
Granted	180,000	<u>\$3.875</u>	<u>3.875 - 3.875</u>
Exercised	(511,584)	<u>\$1.01</u>	<u>.94 - 1.625</u>
Expired	<u>(12,400)</u>	<u>\$3.31</u>	<u>1.50 - 3.75</u>
Outstanding December 31, 2000	<u>1,045,000</u>	<u>\$3.95</u>	<u>1.125 - 6.125</u>
Granted	<u>185,000</u>	<u>\$6.25</u>	<u>6.25 - 6.25</u>
Outstanding December 31, 2001	<u>1,230,000</u>	<u>\$4.29</u>	<u>1.125 - 6.25</u>
Exercised	<u>(70,000)</u>	<u>\$1.125</u>	<u>1.125 - 1.125</u>
Outstanding December 31, 2002	<u>1,160,000</u>	<u>\$4.48</u>	<u>1.125 - 6.25</u>

As of December 31, 2002, there were 140,000 options outstanding and exercisable at the \$1.125 exercise price which have a weighted average remaining contractual life of 2.9 years. Also as of December 31, 2002 there were 1,020,000 options outstanding and exercisable at a \$3.75 to \$6.25 exercise price range having a weighted average remaining contractual life of 5.9 years and weighted average exercise price of \$4.95.

(Continued)

## Notes to Consolidated Financial Statements

Stock Redemption Agreement

The Company has stock redemption agreements with three officers of the Company. The agreements require the Company to maintain life insurance on each executive in the amount of \$1,000,000. The agreements provide that the Company shall utilize the proceeds from such insurance to purchase from such executives' estates or heirs, at their option, shares of the Company's stock. The purchase price for the outstanding common stock is to be based upon the average closing asked price for the Company's stock as quoted by NASDAQ during a specified period. The Company is not required to purchase any shares in excess of the amount provided for by such insurance.

(6) Employee Benefit Plans

The Company made 401-K Plan contributions of \$288,000, \$260,800 and \$252,600 for 2002, 2001 and 2000, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed \$200,000, \$200,000 and \$1,000, to the plan in cash during 2002, 2001 and 2000, respectively.

During 2002, 2001 and 2000 the Company expensed and established a liability for \$90,000 each year under a deferred compensation arrangement with the executive officers of the Company.

At December 31, 2002 and 2001, the Company has recorded as other assets \$501,000 and \$402,100, respectively related to the cash surrender value of the life insurance on certain executive officers.

(7) Earnings Per Share

Basic earnings per share is based on the weighted average number of common shares outstanding of 15,866,363 for 2002, 16,244,931 for 2001 and 16,157,532 for 2000.

Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding of 16,143,414 for 2002, 16,639,634 for 2001 and 16,437,488 for 2000. Stock options are considered to be common stock equivalents and to the extent appropriate, have been added to the weighted average common shares outstanding.

(Continued)

Notes to Consolidated Financial Statements

(8) Transactions with Affiliates

As part of its duties as well operator, the Company received \$60,620,222 in 2002, \$71,802,700 in 2001 and \$44,899,200 in 2000 representing proceeds from the sale of oil and gas and made distributions to investor groups according to their working interests in the related oil and gas properties. Funds held for future distribution on the consolidated balance sheet of \$3,917,900 and \$4,650,800 includes amounts owed to affiliated partnerships as of December 31, 2002 and 2001, respectively.

The Company provided oil and gas well drilling services to affiliated partnerships. Substantially all of the Company's oil and gas well drilling operations was for such partnerships. The Company also provided related services of operation of wells, reimbursement of syndication costs, management fees, tax return preparation and other services relating to the operation of the partnerships. The Company received \$20,008,900 in 2002, \$16,072,500 in 2001 and \$15,713,300 in 2000 for those services. Amounts due from the partnerships as of December 31, 2002 and 2001 were \$1,028,000 and \$1,246,200, and are included in notes and accounts receivable.

During 2002, 2001 and 2000, the Company paid \$51,800, \$30,100 and \$40,400, respectively to the Corporate Secretary's law firm for various legal services.

(9) Commitments and Contingencies

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities and industrial customers. One customer, Cinnabar Energy Services, accounted for 10.8%, 13.1% and 11.3% of total revenues in 2002, 2001 and 2000, respectively.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's hedging instruments or the counterparties to the Company's gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses in 2002, 2001 or 2000.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may tender their partnership units for repurchase at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are tendered, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if tendered by the investors, is currently approximately \$1,878,200. The Company has adequate liquidity to meet this obligation.

The Company is not party to any legal action that would materially affect the Company's results of operations or financial condition.

(10) Lease Obligations

The Company has entered into certain operating leases on behalf of itself and its Partnerships principally for the leasing of natural gas compressors on its Michigan operating facilities. The future minimum lease payments under these non-cancellable operating leases as of December 31, 2002 are as follows:

<u>Year</u>	<u>Lease Amount</u>
2003	\$ 979,300
2004	397,800
2005	120,400
2006	<u>50,200</u>
	<u>\$1,547,700</u>

(Continued)



## Notes to Consolidated Financial Statements

The Company's share of this lease expense for operating leases for the years ended December 31, 2002, 2001 and 2000 was \$660,700, \$693,000 and \$629,800, respectively.

(11) Supplemental Disclosure of Cash Flows

The Company paid \$1,290,400, \$1,173,100 and \$875,800 for interest in 2002, 2001 and 2000, respectively. The Company paid income taxes in 2002, 2001 and 2000 in the amounts of \$175,000, \$2,830,000 and \$2,256,800, respectively.

The Company exchanged common stock in the amount of \$550,000 and paid cash in the amount of \$5,100,000 for the purchase of oil and gas properties in Colorado during 2000.

(12) Acquisitions and Divestitures

On June 6, 2000, the Company purchased all of the working interest in 168 producing wells in Colorado for \$5,650,000. The transaction was effective April 1, 2000. At the date of acquisition, the wells had net remaining reserves of 560,000 barrels of oil and 4.9 billion cubic feet of natural gas. The Company utilized its bank credit agreement to finance this purchase.

On December 31, 2000, the Company sold its Ohio gas gathering and sales systems. The result was a net gain of \$109,600.

(13) Derivative Financial Instruments

The Company utilizes commodity based derivative instruments as hedges to manage a portion of its exposure to price volatility stemming from its integrated natural gas production and marketing activities. These instruments consist of natural gas futures and option contracts traded on the New York Mercantile Exchange for Appalachian and Michigan production and CIG (Colorado Interest Gas Index)-based hedges traded by Bank One for Colorado production. The futures and option contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a 12 month period. The Company does not hold or issue derivatives for trading or speculative purposes. In addition, interest rate swap agreements are used to reduce the potential impact of increases in interest rates on variable rate long-term debt.

Statement of Accounting Standards No. 133 and No. 138, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133/138), was issued by the Financial Accounting Standards Board. SFAS No. 133/138 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. The Company adopted the provisions of the SFAS 133/138 effective January 1, 2001. The natural gas futures and options and the interest rate swap are derivatives pursuant to SFAS 133/138. The Company's derivatives are treated as hedges of committed and/or anticipated transactions and had a total estimated fair value of \$(1,782,000) (net of tax) on December 31, 2002 and a total estimated fair value of \$(457,400) (net of tax) on December 31, 2001.

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

Natural gas futures and option contracts for the sale or purchase of natural gas are as follows:

	Amount (mmbtu)	Fair Value	Fair Value net of tax
<u>December 31, 2002</u>			
Futures contracts			
Marketing activities	3,950,000	\$(1,431,400)	\$(887,400)
Production activities	<u>280,000</u>	<u>(209,700)</u>	<u>(130,000)</u>
	<u>4,230,000</u>	<u>\$(1,641,100)</u>	<u>\$(1,017,400)</u>
Option contracts			
Marketing activities	-	-	-
Production activities	<u>2,950,400</u>	<u>\$(337,200)</u>	<u>(209,100)</u>
	<u>2,950,400</u>	<u>\$(337,200)</u>	<u>\$(209,100)</u>
<u>December 31, 2001</u>			
Futures contracts			
Marketing activities	1,680,000	\$479,300	\$297,200
Production activities	<u>-</u>	<u>-</u>	<u>-</u>
	<u>1,680,000</u>	<u>\$479,300</u>	<u>\$297,200</u>
Option contracts			
Marketing activities	20,000	\$9,000	\$ 5,600
Production activities	<u>-</u>	<u>-</u>	<u>-</u>
	<u>20,000</u>	<u>\$9,000</u>	<u>\$ 5,600</u>

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2002 and 2001, cash in the amount of \$2,760,500 and \$283,300 was on deposit.

Interest rate swap agreements are used to reduce the potential impact of increases in interest rates on variable rate long-term debt. At December 31, 2002 and 2001, the Company was a party to an interest rate swap agreement expiring on October 11, 2004. The agreement entitles the Company, on a quarterly basis, to a fixed-rate interest payment of 6.89% plus its current LIBOR rate margin (+1.50% At December 31, 2002) on a \$10,000,000 notional amount related to its outstanding line of credit.

The fair value of the interest rate swap agreement was \$(896,000), \$(555,000) net of tax at December 31, 2002 and \$(1,226,200), \$(760,200) net of tax at December 31, 2001. Current market pricing models were used to estimate fair value.

By using derivative financial instruments to hedge exposures to changes in interest rates and commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates repayment risk. The Company minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(14) Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred by the Company in oil and gas property acquisition, exploration and development are presented below:

	<u>Years Ended December 31,</u>		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
Property acquisition cost:			
Proved undeveloped properties	\$ 1,892,700	3,670,500	3,397,500
Producing properties	240,000	75,700	8,361,400
Development costs	<u>16,429,400</u>	<u>35,411,900</u>	<u>15,556,200</u>
	<u>\$18,562,100</u>	<u>39,158,100</u>	<u>27,315,100</u>

The proved reserves attributable to the development costs in the above table were 19,607,000 Mcf and 130,000 bbls for 2002, 23,896,000 Mcf and 715,000 bbls for 2001 and 29,060,000 Mcf and 800,000 bbls for 2000 (amounts unaudited). Of the above development costs incurred for the years ended December 31, 2002, 2001 and 2000 the amounts of \$2,699,500, \$7,026,900 and \$2,379,300, respectively were incurred to develop proved undeveloped properties from the prior year end.

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells and to provide facilities to extract, treat, gather and store oil and gas.

(15) Oil and Gas Capitalized Costs

Aggregate capitalized costs for the Company related to oil and gas exploration and production activities with applicable accumulated depreciation, depletion and amortization are presented below:

	<u>December 31,</u>	
	<u>2002</u>	<u>2001</u>
Proved properties:		
Tangible well equipment	\$114,431,800	100,805,800
Intangible drilling costs	64,973,600	61,930,200
Undeveloped properties	<u>4,208,800</u>	<u>4,508,600</u>
	183,614,200	167,244,600
Less accumulated depreciation, depletion and amortization	<u>50,664,600</u>	<u>39,503,200</u>
	<u>\$132,949,600</u>	<u>127,741,400</u>

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PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(16) Results of Operations for Oil and Gas Producing Activities

The results of operations for oil and gas producing activities (excluding marketing) are presented below:

	<u>Years Ended December 31,</u>		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
Revenue:			
Oil and gas sales	\$22,857,100	25,887,900	19,017,300
Expenses:			
Production costs	6,407,900	6,012,400	4,201,400
Depreciation, depletion and amortization	<u>11,149,000</u>	<u>9,665,300</u>	<u>6,031,200</u>
	<u>17,556,900</u>	<u>15,677,700</u>	<u>10,232,600</u>
Results of operations for oil and gas Producing activities before provision For income taxes	5,300,200	10,210,200	8,874,700
Provision for income taxes	<u>1,538,400</u>	<u>2,834,900</u>	<u>2,713,900</u>
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	<u>\$ 3,761,800</u>	<u>7,375,300</u>	<u>6,070,800</u>

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including such costs as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and other production taxes. In addition, production costs include administrative expenses and depreciation applicable to support equipment associated with these activities.

Depreciation, depletion and amortization expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment.

The provision for income taxes is computed at the statutory federal income tax rate and is reduced to the extent of permanent differences, such as investment tax and non-conventional source fuel tax credits and statutory depletion allowed for income tax purposes.

(17) Net Proved Oil and Gas Reserves (Unaudited)

The proved reserves of oil and gas of the Company have been estimated by an independent petroleum engineer, Wright & Company, Inc. at December 31, 2002, 2001 and 2000. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

	Oil (BBLs)		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
Proved developed and undeveloped reserves:			
Beginning of year	2,126,000	2,166,000	1,154,000
Revisions of previous estimates	<u>124,000</u>	<u>(176,000)</u>	<u>10,000</u>
Beginning of year as revised	2,250,000	1,990,000	1,164,000
New discoveries and extensions			
Michigan basin	-	-	265,000
Rocky Mountain region	130,000	715,000	535,000
Dispositions to partnerships	(80,000)	(384,000)	(262,000)
Acquisitions			
Rocky Mountain region	-	-	573,000
Production	<u>(227,000)</u>	<u>(195,000)</u>	<u>(109,000)</u>
End of year	<u>2,073,000</u>	<u>2,126,000</u>	<u>2,166,000</u>
Proved developed reserves:			
Beginning of year	<u>1,801,000</u>	<u>1,527,000</u>	<u>798,000</u>
End of year	<u>1,849,000</u>	<u>1,801,000</u>	<u>1,527,000</u>
	Gas (MCF)		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
Proved developed and undeveloped reserves:			
Beginning of year	118,608,000	118,640,000	101,245,000
Revisions of previous estimates	<u>1,469,000</u>	<u>(8,694,000)</u>	<u>(3,859,000)</u>
Beginning of year as revised	120,077,000	109,946,000	97,386,000
New discoveries and extensions			
Michigan basin	-	-	14,191,000
Rocky Mountain region	19,607,000	23,896,000	14,603,000
Other	-	-	266,000
Dispositions to partnerships	(4,792,000)	(9,263,000)	(8,498,000)
Acquisitions			
Michigan Basin	4,000	-	-
Rocky Mountain region	75,000	2,000	5,761,000
Appalachian basin	342,000	112,000	668,000
Production	<u>(6,462,000)</u>	<u>(6,085,000)</u>	<u>(5,737,000)</u>
End of year	<u>128,851,000</u>	<u>118,608,000</u>	<u>118,640,000</u>
Proved developed reserves:			
Beginning of year	<u>88,477,000</u>	<u>92,131,000</u>	<u>82,628,000</u>
End of year	<u>94,847,000</u>	<u>88,477,000</u>	<u>92,131,000</u>

(18) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves (Unaudited)

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows are computed by applying year-end prices, adjusted for hedging contracts, of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

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PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

	As of December 31,		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
Future estimated revenues	\$548,949,000	317,515,000	520,010,000
Future estimated production costs	(143,878,000)	(98,538,000)	(144,505,000)
Future estimated development costs	(50,971,000)	(45,323,000)	(50,278,000)
Future estimated income tax expense	<u>(105,876,000)</u>	<u>(50,360,000)</u>	<u>(80,982,000)</u>
Future net cash flows	248,224,000	123,294,000	244,245,000
10% annual discount for estimated timing of cash flows	<u>(149,755,000)</u>	<u>(76,855,000)</u>	<u>(139,606,000)</u>
Standardized measure of discounted future estimated net cash flows	<u>\$98,469,000</u>	<u>46,439,000</u>	<u>104,639,000</u>

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

	Years Ended December 31,		
	<u>2002</u>	<u>2001</u>	<u>2000</u>
Sales of oil and gas production, net of production costs	\$(16,449,000)	(19,876,000)	(14,816,000)
Net changes in prices and production costs	143,574,000	(140,487,000)	67,460,000
Extensions, discoveries and improved recovery, less related cost	39,347,000	25,942,000	73,636,000
Dispositions to partnerships	(6,940,000)	(28,935,000)	(16,850,000)
Acquisitions	1,167,000	189,000	27,907,000
Development costs incurred during the period	16,429,000	35,412,000	15,556,000
Revisions of previous quantity estimates	3,318,000	(23,818,000)	(5,925,000)
Changes in estimated income taxes	(55,516,000)	30,622,000	(41,052,000)
Accretion of discount	<u>(72,900,000)</u>	<u>62,751,000</u>	<u>(59,731,000)</u>
	<u>\$ 52,030,000</u>	<u>(58,200,000)</u>	<u>46,185,000</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.

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PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(19) Business Segments (Thousands)

PDC's operating activities can be divided into three major segments: drilling and development, natural gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also engages in oil and gas sales to commercial and industrial end-users. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31, 2002, 2001 and 2000 is as follows:

	<u>2002</u>	<u>2001</u>	<u>2000</u>
REVENUES			
Drilling and Development	\$57,149	76,291	43,195
Oil and Natural Gas Sales	69,223	92,095	90,420
Well Operations	6,116	5,604	5,061
Unallocated amounts (1)	<u>2,854</u>	<u>3,133</u>	<u>2,540</u>
Total	<u>\$135,342</u>	<u>177,123</u>	<u>141,216</u>
	<u>2002</u>	<u>2001</u>	<u>2000</u>
SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and Development	\$7,983	10,291	7,950
Oil and Natural Gas Sales	5,474	10,570	7,364
Well Operations	2,788	2,415	1,385
Unallocated amounts (2)			
General and Administrative expenses	(4,392)	(4,146)	(3,617)
Interest expense	(1,340)	(993)	(1,186)
Other (1)	<u>2,569</u>	<u>2,946</u>	<u>2,378</u>
Total	<u>\$ 13,082</u>	<u>21,083</u>	<u>14,274</u>
	<u>2002</u>	<u>2001</u>	<u>2000</u>
SEGMENT ASSETS			
Drilling and Development	\$31,279	36,202	31,592
Oil and Natural Gas Sales	162,232	142,865	139,116
Well Operations	10,706	11,975	8,490
Unallocated amounts			
Cash	1,736	422	1,567
Other	<u>6,299</u>	<u>8,388</u>	<u>6,920</u>
Total	<u>\$212,252</u>	<u>199,852</u>	<u>187,685</u>
	<u>2002</u>	<u>2001</u>	<u>2000</u>
EXPENDITURES FOR SEGMENT			
LONG-LIVED ASSETS			
Drilling and Development	\$ 1,800	5,963	3,217
Oil and Natural Gas Sales	16,674	35,488	23,958
Well Operations	1,221	839	650
Unallocated amounts	<u>82</u>	<u>371</u>	<u>107</u>
Total	<u>\$ 19,777</u>	<u>42,661</u>	<u>27,932</u>

(1) Includes interest on investments and partnership management fees in 2002, 2001 and 2000 and gain on sale of assets in 2002, 2001 and 2000 which are not allocated in assessing segment performance.

(2) Items which are not allocated in assessing segment performance.

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PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(20) Quarterly Financial Data (Unaudited)

Summarized quarterly financial data for the years ended December 31, 2002 and 2001, are as follows:

	2002				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	\$36,085,900	\$33,468,900	\$28,148,600	\$37,638,500	\$135,341,900
Cost of operations	<u>30,644,300</u>	<u>28,590,800</u>	<u>25,557,500</u>	<u>31,735,400</u>	<u>116,528,000</u>
Gross profit	5,441,600	4,878,100	2,591,100	5,903,100	18,813,900
General and administrative Expenses	975,700	1,027,400	1,069,900	1,318,900	4,391,900
Interest expense	<u>239,300</u>	<u>355,900</u>	<u>399,800</u>	<u>344,800</u>	<u>1,339,800</u>
	<u>1,215,000</u>	<u>1,383,300</u>	<u>1,469,700</u>	<u>1,663,700</u>	<u>5,731,700</u>
Income before income taxes	4,226,600	3,494,800	1,121,400	4,239,400	13,082,200
Income taxes	<u>1,297,600</u>	<u>1,072,900</u>	<u>232,400</u>	<u>1,194,500</u>	<u>3,797,400</u>
Net income	<u>\$2,929,000</u>	<u>\$2,421,900</u>	<u>\$ 889,000</u>	<u>\$ 3,044,900</u>	<u>\$ 9,284,800</u>
Basic earnings per share	<u>\$ .18</u>	<u>\$ .15</u>	<u>\$ .06</u>	<u>\$ .20</u>	<u>\$ .59</u>
Diluted earnings per share	<u>\$ .18</u>	<u>\$ .15</u>	<u>\$ .05</u>	<u>\$ .20</u>	<u>\$ .58</u>
	2001				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	\$59,541,400	\$47,129,000	\$33,336,600	\$37,116,100	\$177,123,100
Cost of operations	<u>50,330,400</u>	<u>40,465,600</u>	<u>27,546,300</u>	<u>32,558,900</u>	<u>150,901,200</u>
Gross profit	9,211,000	6,663,400	5,790,300	4,557,200	26,221,900
General and administrative Expenses	961,400	998,400	1,143,200	1,042,700	4,145,700
Interest expense	<u>213,900</u>	<u>213,700</u>	<u>249,400</u>	<u>316,400</u>	<u>993,400</u>
	<u>1,175,300</u>	<u>1,212,100</u>	<u>1,392,600</u>	<u>1,359,100</u>	<u>5,139,100</u>
Income before					
Income taxes	8,035,700	5,451,300	4,397,700	3,198,100	21,082,800
Income taxes	<u>2,410,700</u>	<u>1,635,400</u>	<u>1,220,200</u>	<u>848,700</u>	<u>6,115,000</u>
Net income	<u>\$5,625,000</u>	<u>\$ 3,815,900</u>	<u>\$ 3,177,500</u>	<u>\$ 2,349,400</u>	<u>\$14,967,800</u>
Basic earnings per share	<u>\$ .35</u>	<u>\$ .23</u>	<u>\$ .20</u>	<u>\$ .14</u>	<u>\$ .92</u>
Diluted earnings per share	<u>\$ .34</u>	<u>\$ .23</u>	<u>\$ .19</u>	<u>\$ .14</u>	<u>\$ .90</u>

Cost of operations include cost of oil and gas well drilling operations, cost of gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.



PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS  
AND RESERVES

Years Ended December 31, 2002, 2001 and 2000

Column A	Column B	Column C	Column D	Column E
<u>Description</u>	<u>Balance at Beginning of Period</u>	<u>Additions, Charged to Costs and Expenses</u>	<u>Deductions</u>	<u>Balance at End of Period</u>
Allowance for doubtful accounts deducted from accounts and notes receivable in the Balance sheet				
2002	<u>\$524,500</u>	<u>\$ -</u>	<u>\$ 29,500</u>	<u>\$495,000</u>
2001	<u>\$524,500</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$524,500</u>
2000	<u>\$438,400</u>	<u>\$573,000</u>	<u>\$486,900</u>	<u>\$524,500</u>