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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

Commission File Number 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	95-2636730
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

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

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

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 X No

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

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

As of February 27, 2004, 15,960,894 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 June 30, 2003, the last business day of the Registrant's most recently completed second quarter was $105,785,917 (based on the last traded price of $9.12).

DOCUMENTS INCORPORATED BY REFERENCE

Document	Form 10-K Part III
Proxy	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, 2003, the Company operates over 2,500 wells located in the Appalachian basin, Michigan, and the Rocky Mountain Region, with gross proved reserves of 468 billion cubic feet equivalent of natural gas ("Bcfe", based on one barrel of oil equals 6 thousand cubic feet equivalent of natural gas ("Mcfe")) of which the Company's share is 199 Bcfe. The Company's share of production for the fourth quarter of 2003 averaged 34,000 Mcfe per day compared to 21,000 Mcfe per day during the fourth quarter of 2002.

The Company's operations are divided into three regions, the Appalachian Basin, Michigan, 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 2003 approximately 19% of production was generated by Appalachian Basin wells, 18% by Michigan Basin wells and 63% by Rocky Mountain wells. As of the end of 2003, the Company's total proved reserves were located as follows: Appalachian Basin 21%, Michigan 13% and Rocky Mountain Region 66%. The majority of the Company's undeveloped reserves are in the Rocky Mountain Region and the planned drilling for 2004 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 and oil.

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 2003, the Company, through four public drilling partnerships, raised $78.3 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. 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 "Financial Information" section of www.petd.com. These reports are posted as soon as reasonably practicable after they are electronically filed with the Securities and Exchange Commission. Additionally, information including the Company's Code of Business Conduct and Ethics is also available at the site.

Industry Overview

Natural gas is the second largest energy source in the United States, after liquid petroleum. The estimated 22.1 Tcf of natural gas consumed in 2003 represented approximately 23% of the total energy used in the United States. Natural gas is consumed in the United States as follows: 36% 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 14% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; and 23% by utilities for the generation of electricity; and 4% for other users. (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 5% 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.

Because 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.

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 22,500 acres available for development in the Piceance Basin, both basins are located in Colorado.

Business Strategy

The Company's objective is to expand its oil and 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 111 wells in 2003, compared to 70 wells in 2002. 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, 2003, the Company had leases or other development rights to 3,100 undeveloped acres in the Michigan Basin, 850 undeveloped acres in the Appalachian Basin and 181,400 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 in areas where the Company is establishing new operations. Acquisitions have historically offered 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. In 1997, the Company expanded its operations from the Appalachian Basin, to Michigan and in late 1999 to the Rocky Mountains. In 2003 over 63% of the Company's production was generated in the Rocky Mountains. The Company plans to conduct the majority of its drilling activities in the Rocky Mountain region during 2004, 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 oil and 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 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, 2003, the Company had leasehold rights to approximately 185,350 acres available for development. 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 2003, the Company drilled a total of 110 development wells all of which were successfully completed as producing wells. During the fourth quarter the Company drilled one exploratory well in Alabama which was dry and according to Successful Efforts Accounting was expensed as an exploratory dry hole. Such dry hole cost amounted to $332,000. 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 the second quarter of 2003, the Company purchased 166 wells in the Denver Julesburg Basin in northeastern Colorado from Williams Production RMT Company for $28 million. The Company estimates the acquisition included approximately 22.6 billion cubic feet (Bcf) of proved developed producing (PDP) and 3.4 Bcf of proved developed non-producing reserves (PDNP), all of which is natural gas.

During the fourth quarter of 2003, the Company purchased from one of its joint venture partners in the Denver-Julesburg Basin in Weld County, Colorado approximately 3.1 billion cubic feet equivalent (Bcfe) of proved developed producing reserves from interests in 20.6 net wells (230 gross) and 1.8 Bcfe of proved developed non-producing reserves from interests in 17 net wells (183 gross). The purchase price was $5.2 million.

During the fourth quarter of 2003, the Company purchased 97 gross wells (73 net) wells in the Denver-Julesburg Basin located in northeast Colorado and northwestern Kansas for $6.0 million. This purchase adds approximately 4.5 billion cubic feet equivalent (Bcfe) of proved developed producing and proved developed non-producing reserves to the Company's oil and gas reserves along with 100,000 acres of oil and gas leases.

Certain well interests in its Company sponsored partnerships were also purchased in 2003, 2002 and 2001.

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,				
	2003	2002	2001	2000	1999
Production(1):					
Oil(MBbls)	289	227	195	109	8
Natural Gas (MMcf)	8,712	6,462	6,085	5,737	3,451
Equivalent MMcfs(2)	10,449	7,824	7,255	6,391	3,499
Average sales price:					
Oil (per Bbl)	$29.39	$24.41	$22.53	$29.99	$18.75
Natural gas (per Mcf)(3)	$4.42	$2.68	$3.53	$2.74	$2.46
Average production cost (lifting cost) per equivalent Mcf(4)	$0.98	$0.82	$0.83	$0.66	$0.69

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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, 2003, 2002, 2001, 2000 and 1999 was $(0.09), $0.02, $(0.56), $(0.91), and $(0.01), respectively.

(4) Production costs represent oil and gas operating expenses which include severance and advalorem taxes as reflected in the financial statements of the Company. See Oil and Gas Production Costs in Management's Discussion and Analysis.

Well Operations

The Company currently operates approximately 1,492 wells in the Appalachian Basin, 204 wells in the Michigan Basin and 834 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 52% ownership interest in the wells it operates.

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

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 last five years. 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 (1.0 net) drilled in 2003 and five dry holes (2.44 net) drilled in 1999.

	Development Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
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	70	13.71	70	13.71	-	-
2003	110	28.51	110	28.51	-	-
Total	591	164.25	577	160.65	14	3.6

Summary of Productive Wells

The table below shows the number of the Company's productive gross and net wells at December 31, 2003.

	Productive Wells			
	Gas		Oil	
Location	Gross	Net	Gross	Net
Colorado	805	480.20	-	-
Kansas	26	21.69	-	-
Michigan	197	109.63	7	2.66
North Dakota	-	-	3	.60
Ohio	10	3.10	-	-
Pennsylvania	531	168.33	-	-
Tennessee	1	0.71	35	13.62
West Virginia	911	514.24	4	1.72
Total	2,481	1,297.90	49	18.60

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 180,998,000 Mcf of natural gas and 3,029,000 Bbls of oil at December 31, 2003, 128,851,000 Mcf of natural gas and 2,073,000 Bbls of oil at December 31, 2002 and 118,608,000 Mcf of natural gas and 2,126,000 Bbls of oil at December 31, 2001.

The Company's approximate net proved developed reserves were estimated, by Wright & Company to be 134,936,000 Mcf of natural gas and 2,889,000 Bbls of oil at December 31, 2003, 94,847,000 Mcf of natural gas and 1,849,000 Bbls of oil at December 31, 2002 and 88,477,000 Mcf of natural gas and 1,801,000 Bbls of oil at December 31, 2001.

The Company's oil and natural gas reserves by region are as follows as of December 31, 2003:

	Oil (Mbbl)	Gas (Mmcf)	Natural Gas Equivalent (Mmcfe)	%
Proved Developed Reserves				
Appalachian Basin	49	41,715	42,009	27.59%
Michigan Basin	43	23,811	24,069	15.81%
Rocky Mountain Region	2,797	69,410	86,192	56.60%
Total Proved Developed Reserves	2,889	134,936	152,270	100.00%
Proved Undeveloped Reserves				
Appalachian Basin	0	0	0	0.00%
Michigan Basin	0	1,488	1,488	3.17%
Rocky Mountain Region	140	44,574	45,414	96.83%
Total Proved Undeveloped	140	46,062	46,902	100.00%
Total Proved Reserves				
Appalachian Basin	49	41,715	42,009	21.09%
Michigan Basin	43	25,299	25,557	12.83%
Rocky Mountain Region	2,937	113,984	131,606	66.08%
Total Proved Reserves	3,029	180,998	199,172	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, 2003. 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 $217.3 million as of December 31, 2003, $98.5 million as of December 31, 2002 and $46.4 million as of December 31, 2001. These amounts are based on year-end prices. 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, 2003 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, 2003 to December 31, 2003, all of which are located within the United States, is shown below:

	Natural Gas (Mcf)	Oil (Bbls)
Proved developed and undeveloped reserves:		
Beginning of year	128,851,000	2,073,000
Revisions of previous estimates	4,394,000	533,000
Beginning of year as revised	133,245,000	2,606,000
New discoveries and extensions		
Rocky Mountain region	27,719,000	517,000
Dispositions to partnerships	(4,410,000)	(112,000)
Acquisitions		
Michigan Basin	265,000	-
Rocky Mountain region	32,169,000	307,000
Appalachian basin	722,000	-
Production	(8,712,000)	(289,000)
End of year	180,998,000	3,029,000
Proved developed reserves:		
Beginning of year	98,847,000	1,849,000
End of year	134,936,000	2,889,000

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 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, 2003 to the future pretax net cash flows, less the tax basis of the properties, and gives effect to permanent differences, tax credits and allowances related to the properties.

	As of December 31, 2003
Future estimated revenues	$1,088,415,000
Future estimated production costs	(250,735,000)
Future estimated development costs	(65,275,000)
Future estimated income tax expense	(265,707,000)
Future net cash flows	506,698,000
10% annual discount for estimated timing of cash flows	(289,408,000)
Standardized measure of discounted future estimated net cash flows	$ 217,290,000

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows from January 1, 2003 through December 31, 2003:

Sales of oil and natural gas production, net of production costs	$(36,810,000)
Net changes in prices and production costs	162,422,000
Extensions, discoveries and improved recovery, less related costs	114,533,000
Dispositions to partnerships	(12,936,000)
Acquisitions	139,078,000
Development costs incurred during the period	30,630,000
Revisions of previous quantity estimates	21,388,000
Changes in estimated income taxes	(159,831,000)
Accretion of discount	(139,653,000)
	$118,821,000

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves, 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, 2003, the acres available for development of oil and natural gas available to the Company, listed alphabetically by state.

Alabama	350
Colorado	152,300
Kansas	28,400
Michigan	3,100
North Dakota	700
West Virginia	500
Total	185,350

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. Three customers accounted for 16.6%, 17.4% and 14.3%, respectively of the Company's revenues from oil and gas sales (9.8%, 10.3% and 8.5% of total revenues in 2003.) Two customers 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 accounted for 25.2% of the Company's revenues from oil and gas sales (13.1% of total revenues) in 2001. No other single purchaser of the Company's natural gas accounted for 10% or more of the Company's total revenues during 2003, 2002 and 2001.

At December 31, 2003, natural gas produced by the Company sold at prices per Mcf ranging from $0.90 to $7.36, 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 2003 was $4.42 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

Some of the Company's wells in the Appalachian Basin and Michigan, and most of the Company's wells in Wattenberg field in Colorado, produce oil in addition to natural gas. At the end of 2003 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 accounted for 11.0% and 11.9% of the Company's revenues from oil and gas sales (6.5% and 5.6% of total revenues) in 2003 and 2002. No customer accounted for more than 10% of the Company's revenues from oil and gas sales in 2001. At December 31, 2003, oil produced by the Company sold at prices ranging from $27.45 to $29.66 per barrel, depending upon the location and quality of oil. In 2003, the weighted net average price per barrel of oil sold by the Company was $29.39.

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 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, 2003 related to oil production, however subsequent to year-end the Company did enter into oil hedge contracts for 2004.

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 $78.3 million in subscriptions in 2003, $56.9 million in subscriptions in 2002 and $57.1 million in subscriptions in 2001. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 22% 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. All 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. 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 ratability 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 2003 were not significant in relation to operating costs and the Company expects no material change in 2004. 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.

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, 2003, the Company had 110 employees, including 17 in finance and data processing, 7 in administration, 11 in exploration and development, 70 in production and 5 in natural gas marketing. The Company's engineers, supervisors and well tenders are 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 has purchased a parcel of land in Greeley Colorado and will construct a field operating office during 2004.

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.

	High	Low
2003		
First Quarter	$ 6.30	$ 5.30
Second Quarter	9.70	6.16
Third Quarter	12.33	8.63
Fourth Quarter	25.05	12.09
2002		
First Quarter	6.65	5.70
Second Quarter	6.66	5.86
Third Quarter	5.95	4.60
Fourth Quarter	5.70	4.75

As of December 31, 2003, there were approximately 1,177 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 6. Selected Condensed Financial Data (1)

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Revenues					
Oil and gas well drilling operations	$71,841,500	$57,149,100	$76,291,200	$43,194,700	$42,115,600
Oil and gas sales	120,162,700	69,223,000	92,095,300	90,419,700	46,988,100
Well operations income	7,347,700	6,116,200	5,604,200	5,061,600	5,314,500
Other income	3,499,100	2,853,600	3,132,400	2,540,500	2,392,400
Total	$202,851,000	$135,341,900	$177,123,100	$141,216,500	$96,810,600
Costs and Expenses (excluding interest and depreciation, depletion and amortization)	$152,445,000	$108,816,600	$144,468,600	$118,813,300	$82,496,500
Interest Expense	$ 1,329,100	$ 1,339,800	$ 993,400	$1,186,000	$ 182,400
Depreciation, depletion and Amortization	$14,153,400	$12,103,300	$10,578,300	$6,943,500	$ 4,031,200
Net Income	$22,619,100	$ 9,284,800	$14,967,800	$10,681,000	$ 7,824,300
Basic earnings per common Share	$1.45	$.59	$.92	$.66	$.50
Diluted earnings per share	$1.39	$.58	$.90	$.65	$.48
Average Common and Common equivalent Shares Outstanding during the Year	16,297,793	16,143,414	16,639,634	16,437,488	16,286,852

	December 31,				
	2003	2002	2001	2000	1999
Total Assets	$306,722,000	$212,251,600	$199,852,100	$187,684,500	$132,083,600
Working Capital	$ 6,230,700	$ 1,770,500	$ 3,419,600	$ 780,700	$ (2,503,900)
Long-Term Debt, excluding current maturities	$ 53,000,000	$ 25,000,000	$ 28,000,000	$ 17,350,000	$ 9,300,000
Stockholders' Equity	$123,604,600	$101,122,200	$ 96,772,800	$ 82,256,900	$70,724,900

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(1) See Consolidated Financial Statements elsewhere herein.

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; the Company's ability to acquire leases and drilling rigs at reasonable prices; 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

Management Overview

The strong market prices for oil and natural gas had a positive impact on many of the Company's operations. High prices directly increased revenue and profitability of sales of oil and gas from Company wells. News of higher oil and gas prices and improved results from prior programs also spurred a significant increase in sales of the Company sponsored drilling programs, and associated profits. To a lesser degree our well operations and gas marketing also benefited from higher prices.

Another major factor contributing to the Company's profitability was the acquisition of producing properties from Williams Company. The increase in production from the acquired properties and high gas prices added to the positive production and revenue numbers.

Year Ended December 31, 2003 Compared with December 31, 2002

Revenues

Total revenues for the year ended December 31, 2003 were $202.9 million compared to $135.3 million for the year ended December 31, 2002, an increase of approximately $67.6 million, or 50.0 percent. Such increase was a result of increased drilling revenues, gas sales from gas marketing activities, oil and gas sales and well operations and pipeline income.

Drilling Revenue

Drilling revenues for the year ended December 31, 2003 were $71.8 million compared to $57.1 million for the year ended December 31, 2002, an increase of approximately $14.7 million or 25.7 percent. Such increase was due to the increased drilling funds raised through the Company's Public Drilling Programs. The four drilling programs of 2003 raised $78.3 million compared to $56.9 million in 2002. We believe this increase is fueled by the increase in oil and natural gas prices which has improved the performance of our prior programs which in turn has helped to increase our drilling program sales.

Natural Gas Marketing Activities

Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's marketing subsidiary for the year ended December 31, 2003 were $73.1 million compared to $46.4 million for the year ended December 31, 2002, an increase of approximately $26.7 million or 57.5 percent. Such increase was due to natural gas sold at significantly higher average sales prices offset in part by slightly lower volumes sold.

Oil and Gas Sales

Oil and gas sales from the Company's producing properties for the year ended December 31, 2003 were $47.0 million compared to $22.9 million for the year ended December 31, 2002, an increase of $24.1 million or 105.2 percent. The increase was due to significantly increased volumes sold at substantially higher average sales prices of oil and natural gas. The volume of natural gas sold for the year ended December 31, 2003 was 8.7 million Mcf at an average sales price of $4.42 per Mcf compared to 6.5 million Mcf at an average sales price of $2.68 per Mcf for the year ended December 31, 2002. Oil sales were 289,000 barrels at an average sales price of $29.39 per barrel for the year ended December 31, 2003 compared to 227,000 barrels at an average sales price of $24.41 per barrel for the year ended December 31, 2002. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily the Williams property acquisition in the second quarter, recompletions of existing wells, two fourth quarter acquisitions of oil and gas properties in Colorado and Kansas and to a lesser extent the investment in oil and gas properties we own with our public drilling program partnerships. The table below outlines our increased production in Mcf equivalents of our 2003 recompletions and acquisitions by quarter.

	Mcfe				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Recompletions	40,000	161,000	223,000	285,000	709,000
Williams Acquisition	-	453,000	573,000	519,000	1,545,000
4th Quarter Acquisitions	-	-	-	196,000	196,000
	40,000	614,000	796,000	1,000,000	2,450,000

Oil and Gas Production

The Company's oil and gas production by area of operations along with average sales price is presented below:

	Year Ended December 31, 2003			Year Ended December 31, 2002		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	3,992	1,921,200	1,945,152	5,814	2,095,903	2,130,787
Michigan Basin	6,627	1,832,737	1,872,499	8,443	2,146,101	2,196,759
Rocky Mountains	278,874	4,958,245	6,631,489	212,779	2,220,033	3,496,707
Total	289,493	8,712,182	10,449,140	227,036	6,462,037	7,824,253
Average Price	$29.39	$4.42	$4.50	$24.41	$2.68	$2.92

Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas and oil markets has remained prevalent in the last few years and can have a material impact on our financial results. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. 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 of 2002 and continuing in 2003, Colorado prices began to increase, although they continue to trail prices in other areas. The Company believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity problem. The Company has commodity price hedging contracts for oil and natural gas production from January 2004 through October 2005 to protect against possible short-term price weaknesses.

Oil and Gas Hedging Activities

Because of uncertainty surrounding natural gas prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2005 we have in place a series of floors and ceilings on part of our natural gas production. Under the 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. During the three months ended December 31, 2003 the Company averaged natural gas volumes sold of 857,000 Mcf per month and oil sales of 31,400 barrels per month. The current positions in effect on the Company's share of production are shown in the following table.

	Floors		Ceilings	
Month	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
NYMEX Based Hedges - (Appalachian and Michigan Basins)				
Jan 2004	114,000	$4.45	57,000	$5.40
Feb 2004	114,000	$4.30	57,000	$5.25
Mar 2004	114,000	$4.20	57,000	$5.00
Apr 2004 - Oct 2004	81,000	$4.00	81,000	$5.65
Apr 2004 - Oct 2004*	122,000	$5.00	-	-
Apr 2005 - Oct 2005*	122,000	$4.28	61,000	$5.00
Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)				
Jan 2004 - Mar 2004	20,000	$3.50	20,000	$5.25
Apr 2004 - Oct 2004	25,000	$3.20	25,000	$4.70
Apr 2004 - Oct 2004*	25,000	$4.17	-	-
Apr 2005- Oct 2005*	33,000	$3.10	16,000	$4.43
NYMEX Based Hedges (Williams acquisition)				
Jan 2004 - Dec 2004	150,000	$4.50	-	-
Apr 2005 - Oct 2005*	150,000	$4.26	75,000	$5.00

Oil hedges (Wattenberg Field)

Month	Monthly Quantity Bbl	Contract Price
Mar 2004 - Dec 2004*	10,000	$31.60

*Entered into during 2004

Well Operations, Pipeline & Other Income

Well operations and pipeline income for the year ended December 31, 2003 was $7.3 million compared to $6.1 million for the year ended December 31, 2002, an increase of approximately $1.2 million or 19.7 percent. Such increase was due to an increase in the number of wells and pipeline systems operated by the Company for our Drilling Fund Partnerships as well as joint ventures. Other income for the year ended December 31, 2003 was $3.5 million compared to $2.9 million for the year ended December 31, 2002. Such increase was due to receiving the proceeds of $1.0 million in life insurance offset in part by a reduction in sales of miscellaneous items.

Costs and Expenses

Costs and expenses for the year ended December 31, 2003 were $167.9 million compared to $122.3 million for the year ended December 31, 2002, an increase of approximately $45.6 million or 37.3 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, gas purchased for gas marketing activities, oil and gas production costs and depreciation, depletion and amortization.

Oil and Gas Well Drilling Costs

Oil and gas well drilling operations costs for the year ended December 31, 2003 were $61.3 million compared to $49.2 million for the year ended December 31, 2002, an increase of approximately $12.1 million or 24.6 percent. Such increase was due to the higher levels of drilling activity from our Public Drilling Programs referred to above.

Cost of Gas Marketing Activities

The cost of gas marketing activities for the year ended December 31, 2003 were $72.4 million compared to $46.2 million for the year ended December 31, 2002, an increase of $26.2 million or 56.7 percent. The increase was due to the significantly higher average prices of natural gas purchased and offset in part by slightly lower volumes purchased for resale. Income before income taxes for the Company's natural gas marketing subsidiary improved from $174,000 for the year ended December 31, 2002 to $689,000 for the year ended December 31, 2003. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period.

Oil and Gas Production Costs

Oil and gas production costs from the Company's producing properties for the year ended December 31, 2003 were $13.7 million compared to $9.1 million for the year ended December 31, 2002, an increase of approximately $4.6 million or 50.5% percent. Such increase was due to the increased production costs and severance and property taxes on the increased volumes and higher sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. Lifting cost per Mcfe increased from $.82 per Mcfe to $.98 per Mcfe which is almost entirely attributed to the increase in severance and property taxes on the significantly increased oil and gas sales prices.

General and Administrative Costs

General and administrative expenses for the year ended December 31, 2003 increased to $4.9 million compared with $4.4 million for the year ended December 31, 2002 an increase of approximately $500,000 or 11.4%, such increase was due to the increased administrative activity associated with a growing Company.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization costs for the year ended December 31, 2003 increased to $14.2 million from approximately $12.1 million for the year ended December 31, 2002, an increase of approximately $2.1 million or 17.4%. Such increase was due to the significantly increased production and investment in oil and gas properties by the Company as referred to above.

Interest Expense

Interest costs for the year ended December 31, 2003 and 2002 were $1.3 million. The lower average effective interest rates in 2003 more than offset the higher average borrowing levels the Company experienced during 2003, primarily a result of the oil and gas property acquisitions mentioned above.

Provision for Income Taxes

The effective income tax rate for the Company's provision for income taxes increased from 29% to 34.7% primarily as a result of the expired non-conventional source fuel tax credit and the effect of the federal rate change to 35% because of significantly increased earnings of the Company during 2003.

Change in Accounting Principle

The Company adopted SFAS No. 143 *"Accounting for Asset Retirement Obligations"* on January 1, 2003 and booked the cumulative effect on prior years of $198,600 (net of taxes of $121,700).

Net income and Earnings Per Share

Net income for the year ended December 31, 2003 was $22.6 million compared to a net income of $9.3 million for the year ended December 31, 2002, an increase of approximately $13.3 million or 143% percent.

Diluted earnings per share for the year ended December 31, 2003 was $1.39 per share compared to $.58 per share for the year ended December 31, 2002, an increase of $.81 per share or 139.7 percent.

<u>Year Ended December 31, 2002 Compared with December 31, 2001</u>

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%.

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 and oil from the Company's well interests, natural gas marketing, well drilling and operating activities from the Company's public drilling programs, and natural gas gathering and transportation. 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 Pricing and Pipeline Capacity

Natural gas and oil prices have been unusually volatile for the past few years, 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 2004 although natural gas storage levels are near normal levels following a period when storage levels had been at a five-year low. The Company believes this situation creates the possibility of both periods of low prices and continued high prices.

Natural gas prices declined dramatically at the end 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 of 2002 and continuing in 2003, Colorado prices began to increase, although they continue to trail prices in other areas. The Company believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity problem.

Oil and Gas Hedging Activities

Because of the uncertainty surrounding natural gas and oil prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through October of 2005 we have in place a series of floors and ceilings on part of our natural gas production. Under the 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. See previous pages in this Management's Discussion and Analysis for a schedule of hedging positions.

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 Pricing

Oil prices have strengthened since the middle of 2003. While oil prices are influenced by supply and demand, global geopolitics may be the single most important determinant. Since the percentage of the Company's production reflected by oil sales has increased to 17%, variations in oil prices will have a greater impact on the Company than in the past. The Company also has in place hedges on 10,000 barrels a month for its Wattenburg Field oil production for the period from March 2004 through December 2004 at a price of $31.60 per barrel.

Public Drilling Programs

The Company closed four public drilling partnerships during 2003. The total amount received during 2003 was $78.3 million compared to $56.9 million for 2002. The Company closed its fourth program of 2003 on December 15, 2003 in the amount of $35.0 million and will drill the wells during the first quarter of 2004. The last three drilling partnerships of 2003 closed at their maximum allowable subscriptions, earlier than the scheduled close. The result of these maximum closings is that the Company has a drilling carryover to 2004 of $50.5 million compared with $37.3 million at the end of 2002. The response to the Company's first program of 2004 is strong. It is scheduled to close on April 30, 2004, its maximum allowable subscriptions is $30.0 million. Additional programs are scheduled to close in August, October and December of 2004. The Company invests, as its equity contribution to each drilling partnership, an additional sum of 21.75% 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. 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 request the Company to repurchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if investors request the Company to repurchase such units subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $4.8 million. The Company has adequate liquidity to meet this obligation. During 2003 the Company has spent $266,500 under this provision.

Acquisition of Oil and Gas Properties

During the second quarter of 2003, the Company purchased 166 wells in the Denver Julesburg Basin in northeastern Colorado from Williams Production RMT Company for $28 million. The Company estimates the acquisition included approximately 22.6 billion cubic feet (Bcf) of proved developed producing (PDP) and 3.4 Bcf of proved developed non-producing reserves (PDNP), all of which is natural gas.

During the fourth quarter of 2003, the Company purchased from one of its joint venture partners in the Denver-Julesburg Basin in Weld County, Colorado approximately 3.1 billion cubic feet equivalent (Bcfe) of proved developed producing reserves from interests in 20.6 net wells (230 gross) and 1.8 Bcfe of proved developed non-producing reserves from interests in 17 net wells (183 gross). The purchase price was $5.2 million.

During the fourth quarter of 2003, the Company purchased 97 gross wells (73 net) wells in the Denver-Julesburg Basin located in northeast Colorado and northwestern Kansas for $6.0 million. This purchase adds approximately 4.5 billion cubic feet equivalent (Bcfe) of proved developed producing and proved developed non-producing reserves to the Company's oil and gas reserves along with 100,000 acres of oil and gas leases. The Company funded the above acquisitions through its bank credit facility.

Costs incurred by the Company in oil and gas acquisitions, exploration and development for the year ended December 31, 2003 are presented below:

Property acquisition cost:	
Proved undeveloped properties	$ 6,167,800
Producing properties	33,946,600
Development costs	30,630,100
	$70,744,500

Common Stock Repurchase

On March 13, 2003 the Company publicly announced a common stock repurchase program to repurchase up to 5% of the Company's outstanding common stock (785,000 shares) expiring on December 31, 2004. From inception of the program until December 31, 2003, the Company has repurchased 109,200 shares at an average price of $6.86 per share. The Company intends to fund this repurchase of common stock through internally generated cash flow.

Long-Term Debt

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 $80.0 million, of which the Company has activated $60.0 million of the facility. As of December 31, 2003, the outstanding balance on the line of credit was $53.0 million of which $10.0 million was subject to an interest rate swap at a rate of 8.39% , $15.0 million was subject to a 90-day LIBOR rate of 2.87%, $5.0 million subject to a 30-day LIBOR rate of 2.92% and the remaining $23.0 million was subject to a prime rate of 4.00%. 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 anticipates extending the expiration date during the first half of 2004.

Contractual Obligations

Contractual obligations and due dates are as follows:

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$53,000,000	-	$53,000,000	-	-
Operating Leases	833,200	$366,300	308,300	$158,600	-
Asset Retirement Obligation	731,200	-	50,000	50,000	$631,200
Other Liabilities	2,449,100	100,000	250,000	250,000	1,849,100
Total	$57,013,500	$466,300	$53,608,300	$458,600	$2,480,300

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.

Commitments and Contingencies

As Managing General Partner of 10 private partnership and 58 public partnerships (See Item 2. Properties - Financing of Drilling Activities) the Company has liability for any potential casualty losses in excess of the partnership assets and insurance. The Company believes its and its subcontractors casualty insurance coverage is adequate to meet this potential liability.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to our business operations and the understanding of our results of operations. This listing is not a comprehensive list of all of our accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by accounting principles generally accepted in the United States, with no need for management's judgment in their application. There are also areas in which management's judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and may require the application of significant judgment by our management; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, our management uses its judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on our historical experience, our observance of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see "Note 1 - Summary of significant account policies" in our financial statements and related notes. Our critical accounting policies and estimates 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 and pipeline income consists of operation charges for well upkeep, maintenance, transportation of natural gas 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 the Company's history of write-offs, relationships and overall credit worthiness of its customers, and well production data for receivables related to well operations.

Accounting for Derivatives Contracts at Fair Value

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

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

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

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

Use of Estimates in Long-Lived Asset Impairment Testing

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

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

Unproved properties or leases are written-off to expense when it is determined that they will expire or be abandoned.

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 Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect on change in accounting principle on prior years of $198,600 (net of taxes of $121,700).

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. Disclosures required by this standard are included in the notes to these financial statements.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS no. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights (leases) associated with extracting oil and gas intangible assets in the balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify the historical cost of approximately $7,576,900 and $4,208,800 of mineral rights associated with undeveloped oil and gas properties and $15,485,500 and $10,898,700 of mineral rights associated with developed oil and gas properties as of December 31, 2003 and December 31, 2002, respectively, out of oil and gas properties and into a separate intangible mineral rights assets line item. The Company's total balance sheet, cash flows and results of operations would be not affected since such intangible assets would continue to be amortized and assessed for impairment.

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

Market-Sensitive Instruments and Risk Management

The 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, 2003 is $85,184,700 with an average interest rate of 0.57%. As of December 31, 2003, the Company has long-term debt of $53,000,000 of which $10,000,000 is subject to an interest rate swap at a rate of 8.39%, $15,000,000 subject to a 90-day LIBOR rate of 2.87%, $5,000,000 was subject to a 30-day LIBOR rate of 2.92% and $23,000,000 was subject to a prime rate of 4.00%.

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, 2003 RNG had entered into a series of natural gas future contracts stemming from its marketing activities. Total open futures contracts are for the sale of 2,660,000 Mmbtu of natural gas with a weighted average price of $4.58 Mmbtu resulting in a total contract amount of $12,174,100 and a fair market value of $(1,810,500) and for the purchase of 820,000 Mmbtu of natural gas with a weighted average price of $5.17 Mmbtu resulting in a total contract amount of $4,243,400 and a fair market value of $270,200. Open future contracts maturing in 2004 are for the sale of 2,060,000 mmbtu of natural gas with a weighted average price of $4.66 mmbtu resulting in a total contract amount of $9,594,200 and a fair market value of $(1,562,100) and for the purchase of 820,000 mmbtu of natural gas with a weighted average price of $5.17 mmbtu resulting in a total contract amount of $4,243,400 and a fair market value of $270,200. The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 25 months. There were no open option contracts stemming from RNG's marketing activities as of December 31, 2003. As of December 31, 2002, RNG had entered into a series of natural gas future contracts and option contracts stemming from its marketing activities. Open future contracts as of December 31, 2002 that matured in 2003 were for the sale of 3,210,000 mmbtu of natural gas with a weighted average price of $3.18 Mmbtu resulting in a total contract amount of $12,728,100 and a fair market value of $(1,912,200).

As of December 31, 2003, 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 2004 are for the sale of 53,300 Mmbtu of natural gas with a weighted average price of $5.40 Mmbtu resulting in a total contract amount of $288,000 and a fair market value of $(40,000) and for the purchase of 45,700 Mmbtu of natural gas with a weighted average price of $4.77 resulting in a total contract amount of $218,100 and a fair value of $30,400. Open option contracts maturing in 2004 are for the sale of 2,597,800 Mmbtu with a weighted average floor price of $4.29 Mmbtu and a fair value of $185,300 and 691,200 Mmbtu with a weighted average ceiling price of $5.23 Mmbtu and a fair value of $(127,800). The maximum term over which PDC is hedging exposure to variability of cash flows for commodity price risk is 12 months. 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 as of December 31, 2002 that matured in 2003 were 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 as of December 31, 2002 that matured in 2003 were 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).

The average NYMEX closing price for natural gas for the years 2003, 2002 and 2001 was $5.39 Mmbtu, $3.22 Mmbtu, and $4.27 Mmbtu. The average NYMEX closing price for oil for the years 2003, 2002 and 2001 was $30.98 bbl, $26.98 bbl and $26.60 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, 2003, 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.

Item 8. Financial Statements and Supplementary Data:

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

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

None.

Item 9A Controls and Procedures

Under the supervision and with the participation of the 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)) as of the end of the period covered by this annual report on Form 10-K, and, based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective in all material respects, including those to ensure that information required to be disclosed in reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in the Commission's rules and forms, and is accumulated and communicated to management, including the 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 in the fourth quarter and subsequent to the date of their evaluation.

PART III

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
Steven R. Williams	52	Chairman, Chief Executive Officer,	January 2004
		President and Director	March 1983
Darwin L. Stump	48	Chief Financial Officer and Treasurer	November 2003
Thomas E. Riley	51	Executive Vice President Production, Natural Gas Marketing and Business Development, and Director	November 2003
Eric R. Stearns	46	Executive Vice President Exploration and Development	November 2003
Roger J. Morgan	76	Secretary	November 1969
Vincent F. D'Annunzio	51	Director	February 1989
Jeffrey C. Swoveland	48	Director	March 1991
Donald B. Nestor	55	Director	March 2000
Kimberly Luff Wakim	45	Director	January 2003
David C. Parke	37	Director	November 2003

Steven R. Williams was elected Chairman and Chief Executive Officer in January 2004. Mr. 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.

Darwin L. Stump was appointed Chief Financial Officer and Treasurer in November 2003. Mr. Stump has been an officer of the Company since April 1995 and held the position of Corporate Controller since 1980. Mr. Stump, a CPA, was a senior accountant with Main Hurdman, Certified Public Accountants prior to joining PDC.

Thomas E. Riley was elected Director in January 2004 by the Board of Directors and appointed Executive Vice President of Production, Natural Gas Marketing and Business Development in November 2003. Prior thereto, Mr. Riley served as Vice President Gas Marketing and Acquisitions of PDC since April 1996. Prior to joining PDC, Mr. Riley was president of Riley Natural Gas Company, a natural gas marketing company which PDC acquired in April 1996.

Eric R. Stearns was appointed Executive Vice President of Exploration and Development in November 2003. Prior thereto, Mr. Stearns was Vice President of Exploration and Development since April 1995. Mr. Stearns joined PDC as a geologist in 1985 after working for Hywell, Incorporated and for Petroleum Consultants.

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

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

David C. Parke was elected Director by the Board of Directors in November 2003. In 2003, Mr. Parke joined Mufson/Howe/Hunter & Company LLC, an investment banking firm as a founder and Director. From 1992-2003, Mr. Parke was with the corporate finance department of Investec, Inc. and its predecessor Pennsylvania Merchant Group Ltd., investment banking companies. Prior to joining Pennsylvania Merchant Group, Mr. Parke served in the corporate finance departments of Wheat First Butcher & Singer, now part of Wachovia Securities, and Legg Mason, Inc.

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. D'Annunzio is a member of the class whose term expires in 2004; Mr. Parke and Mr. Riley were elected by the Board to fulfill unexpired terms that expire in 2004. Mr. Swoveland is a member of the class whose term expires in 2005. Mr. Williams, Mr. Nestor and Ms. Wakim are members of the class whose term expires in 2006. 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 policy is posted on the Company's website at www.petd.com.

The Audit Committee of the Board of Directors is comprised entirely of independent directors as defined by the NASDAQ rule 4200(a)(15). 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.

The Nominating and Governance and Compensation Committees are also comprised entirely of independent directors of the Company. Vincent F. D'Annunzio chairs the Nominating and Governance Committee, and Jeffrey C. Swoveland chairs the Compensation Committee.

Shareholders wishing to communicate with the Board of Directors or a committee may do so by writing to the attention of the Board or Committee at the corporate headquarters or by emailing the Board at board@petd.com, with "Board" or appropriate committee in the subject line.

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 2004 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2004.

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 2004 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2004.

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

Equity Compensation Plan Information
December 31, 2003

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 2004 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2004.

Item 14. Principal Accounting Fees and Services

The information under the caption "Fees Billed by Independent Public Accountants for Services in 2003 and 2002" in the Company's definitive Proxy Statement in connection with the 2004 annual stockholders' meeting is incorporated by reference.

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.

CONFORMED COPY

SIGNATURES

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

PETROLEUM DEVELOPMENT CORPORATION

By /s/ Steven R. Williams
Steven R. Williams, Chairman

March 2, 2004

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

Signature	Title	Date
/s/ Steven R. Williams Steven R. Williams	Chairman, Chief Executive Officer, President and Director	March 2, 2004
/s/ Darwin L. Stump Darwin L. Stump	Chief Financial Officer and Treasurer (principal financial and accounting officer)	March 2, 2004
/s/ Thomas E. Riley Thomas E. Riley	Executive Vice President of Production , Natural Gas Marketing and Business Development and Director	March 2, 2004
/s/ Donald B. Nestor Donald B. Nestor	Director, Chairman of Audit Committee	March 2, 2004
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	March 2, 2004
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	March 2, 2004
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	March 2, 2004
/s/ David C. Parke David C. Parke	Director	March 2, 2004

Exhibits Index

(a) Exhibitis

Exhibit Name	Exhibit Number	Location
Articles of Incorporation	3.1	Incorporated by reference to Exhibit 3.1 to Form S-2 SEC File No. 333-36369 filed on September 25, 1997
By Laws	3.2	Incorporated by reference to Exhibit 3.2 to Form 8-K SEC File No. 0-07246 filed on January 24, 2003
Credit Agreement, dated as of July 3, 2002 by and between Petroleum Development Corporation and the lenders, Bank One N.A. and BNP Paribas	10.1	Incorporated by reference to Exhibit 10.1 to Form 10-K for year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003
Employment Agreement -Steven R. Williams, President	10.2	Incorporated by reference to Exhibit 10.2 to Form 10-K for year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003
Employment Agreement - Darwin L. Stump, Chief Financial Officer	10.3	Incorporated by referenced to Exhibit 99 to Form 8-K, SEC File No. 0-07246 filed on January 5, 2004
Employment Agreement -Thomas E. Riley, Executive Vice President	10.4	Incorporated by reference to Exhibit 99 to Form 8-K, SEC File No. 0-07246 filed on January 5, 2004
Employment Agreement - Eric R. Stearns, Executive Vice President	10.5	Incorporated by reference to Exhibit 99 to Form 8-K SEC File No. 0-07246 filed on January 5, 2004
Code of Business Conduct and Ethics	14	Incorporated by reference to Exhibit 3.1 to Form 10-K for the year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003
Subsidiaries	21	Riley Natural Gas Company, a West Virginia Corporation
	21	PDC Securities Incorporated, a West Virginia Corporation
Rule 13a-14(a)/15d-14(a) Certification by Chief Executive Officer	31.1	Filed herewith.
Rule 13a-14(a)/15d-14(a)Certification by Chief Financial Officer	31.2	Filed herewith.
Section 1350 Certifications by Chief Executive Officer	32.1	Filed herewith.
Section 1350 Certifications by Chief Financial Officer	32.2	Filed herewith.

(b) Reports on Form 8-K during quarter ended December 31, 2003.

Form 8-K current report dated December 23, 2003, under Item 5. "Other Matters" the Company issued a news release announcing it closed the purchase of interests in oil and natural gas properties in the Denver-Julesburg Basin.

Form 8-K current report dated December 5, 2003, under Item 5. "Other Matters" the Company issued a news release announcing the closing of the fourth 2003 drilling program

Form 8-K current reported dated November 19, 2003, under Item 5. "Other Matters" the Company issued a news release announcing the appointment of several new officers for Petroleum Development.

Form 8-K current report dated November 10, 2003, under Item 5. "Other Matters" the Company issued a news release announcing that David C. Parke has been appointed by the Board of Directors to fill the position vacated by Dale G. Rettinger in October. Mr. Rettinger passed away unexpectedly on October 3 after a brief illness.

Form 8-K current report dated November 4, 2003, under Item 5. "Other Matters" the Company issued a news release announcing the Petroleum Development Reports Record Closing for Third 2003 Drilling Program and on November 5, 2003, the Company issued a news release announcing the Petroleum Development Adds to Natural Gas Commodities Options Positions.

Form 8-K current report dated November 3, 2003, under Item 5. "Other Matters" the Company issued a news release announcing 3rd quarter 2003 earnings.

Form 8-K current report dated October 22, 2003, under Item 5. "Other Matters" the Company issued a news release announcing its upcoming third quarter earnings release on November 3rd and upcoming conference call to discuss earnings on November 4th.

Form 8-K current report dated October 6, 2003, under Item 5. "Other Matters", the Company issued a news release announcing the passing of Dale G Rettinger, Executive Vice President and Chief Financial Officer and that Darwin L. Stump, the Company's controller, has been named as acting CFO.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Index to Financial Statements and Financial Statement Schedules

1.	Financial Statements:	
	Independent Auditors' Report	F-2
	Consolidated Balance Sheets - December 31, 2003 and 2002	F-3 & 4
	Consolidated Statements of Income - Years Ended December 31, 2003, 2002 and 2001	F-5
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2.	Financial Statement Schedule:	
	Schedule II - Valuation and Qualifying Accounts and Reserves	F-27

<u>Independent Auditors' Report</u>

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, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, 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 1 to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, in 2003. 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 27, 2004

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2003 and 2002

Assets	2003	2002
Current assets:		
Cash and cash equivalents	$ 78,512,900	$ 48,263,000
Restricted cash	1,866,400	2,760,500
Notes and accounts receivable	22,523,600	15,336,500
Inventories	2,557,700	1,174,100
Prepaid expenses	5,907,000	4,125,300
Total current assets	111,367,600	71,659,400
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	251,558,900	183,614,200
Pipelines	9,097,000	7,015,000
Transportation and other equipment	3,460,900	3,174,200
Land and buildings	1,747,500	1,455,400
	265,864,300	195,258,800
Less accumulated depreciation, depletion and amortization	71,182,100	57,143,700
	194,682,200	138,115,100
Other assets	672,200	2,477,100
	$306,722,000	$212,251,600

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2003 and 2002

	2003	2002
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 29,453,000	$ 17,425,500
Other accrued expenses	16,814,200	11,261,700
Advances for future drilling contracts	50,458,800	37,283,800
Funds held for future distribution	8,410,900	3,917,900
Total current liabilities	105,136,900	69,888,900
Long-term debt	53,000,000	25,000,000
Other liabilities	2,449,100	4,137,200
Deferred income taxes	21,800,200	12,103,300
Asset retirement obligation	731,200	-
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 15,628,433 and 15,734,767 shares	156,200	157,300
Additional paid-in capital	28,578,100	29,316,800
Retained earnings	96,049,200	73,430,100
Accumulated other comprehensive loss, net of tax	(1,178,900)	(1,782,000)
Total stockholders' equity	123,604,600	101,122,200
	$306,722,000	$212,251,600

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Income

Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
Revenues:			
Oil and gas well drilling operations	$71,841,500	57,149,100	76,291,200
Gas sales from marketing activities	73,141,100	46,365,900	66,207,400
Oil and gas sales	47,021,600	22,857,100	25,887,900
Well operations and pipeline income	7,347,700	6,116,200	5,604,200
Other income	3,499,100	2,853,600	3,132,400
	202,851,000	135,341,900	177,123,100
Costs and expenses:			
Cost of oil and gas well drilling operations	61,277,800	49,166,200	65,999,900
Cost of gas marketing activities	72,443,600	46,184,300	65,740,300
Oil and gas production and well operations costs	13,749,200	9,074,200	8,582,700
General and administrative expenses	4,974,400	4,391,900	4,145,700
Depreciation, depletion and amortization	14,153,400	12,103,300	10,578,300
Interest	1,329,100	1,339,800	993,400
	167,927,500	122,259,700	156,040,300
Income before income taxes and cumulative effect of change in accounting principle	34,923,500	13,082,200	21,082,800
Income taxes	12,105,800	3,797,400	6,115,000
Net income before cumulative effect of change in accounting principle	22,817,700	9,284,800	14,967,800
Cumulative effect of change in accounting principle (net of taxes of $121,700)	(198,600)	-	-
Net income	$22,619,100	9,284,800	14,967,800
Basic earnings per common share before accounting change	$1.46	.59	.92
Cumulative effect of change in accounting principle	(0.01)	-	-
Basic earnings per common share	$1.45	.59	.92
Diluted earnings per share before accounting change	$1.40	.58	.90
Cumulative effect of change in accounting principle	(0.01)	-	-
Diluted earnings per common and common equivalent share	$1.39	.58	.90

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 2003, 2002 and 2001

	Common stock issued					
	Number Of Shares	Amount	Additional Paid-in-capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2000	16,244,044	$162,400	32,917,000	49,177,500	-	82,256,900
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)	-	-	-	-	6,650,500	
Other comprehensive loss					(457,400)	(457,400)
Comprehensive income						14,510,400
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)	-	-	-	-	(1,339,400)	
Other comprehensive loss					(1,324,600)	(1,324,600)
Comprehensive income						7,960,200
Balance, December 31, 2002	15,734,767	157,300	29,316,800	73,430,100	(1,782,000)	101,122,200
Amortization of stock award		-	8,900	-	-	8,900
Repurchase and cancellation of treasury stock, net	(106,334)	(1,100)	(747,600)			(748,700)
Net income	-	-	-	22,619,100	-	22,619,100
Comprehensive income:						
Reclassification adjustment for settlement of contracts Included in net income (net of tax of $583,900)	-	-	-	-	917,200	
Changes in fair value of outstanding hedging positions and interest rate swap (net of tax of $200,000)	-	-	-	-	(314,100)	
Other comprehensive income					603,100	603,100
Comprehensive income						23,222,200
Balance, December 31, 2003	15,628,433	$ 156,200	28,578,100	96,049,200	(1,178,900)	123,604,600

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
Cash flows from operating activities:			
Net income	$22,619,100	9,284,800	14,967,800
Adjustment to reconcile net income to cash provided by operating activities:			
Deferred income taxes	8,870,700	2,986,400	4,002,400
Depreciation, depletion and amortization	14,153,400	12,103,300	10,578,300
Cumulative effect of change in accounting principle	198,600	-	-
Gain from sale of assets	(115,800)	(25,800)	(132,400)
Expired and abandoned leases	1,418,400	1,129,400	919,100
Amortization of stock award	8,900	5,500	5,500
(Increase) decrease in notes and accounts receivable	(7,187,100)	(4,583,900)	12,895,400
Increase in inventories	(1,383,600)	(56,200)	(20,000)
(Increase) decrease in prepaid expenses	(1,095,900)	369,200	3,243,900
Decrease in other assets	1,696,200	56,300	336,700
Increase (decrease) in accounts payable and accrued expenses	16,757,000	1,945,200	(8,219,900)
Increase (decrease) in advances for future drilling contracts	13,175,000	5,691,600	(12,217,200)
Increase (decrease) in funds held for future distribution	4,493,000	(732,900)	2,210,700
Total adjustments	50,988,800	18,888,100	13,602,500
Net cash provided by operating activities	73,607,900	28,172,900	28,570,300
Cash flows from investing activities:			
Capital expenditures	(73,042,300)	(19,777,000)	(42,661,100)
Proceeds from sale of leases	1,382,100	1,042,500	4,732,200
Proceeds from sale of fixed assets	156,800	25,800	12,200
Decrease (increase) in restricted cash	894,100	(2,477,200)	2,655,000
Net cash used in investing activities	(70,609,300)	(21,185,900)	(35,261,700)
Cash flows from financing activities:			
Proceeds from (retirement of) debt, net	28,000,000	(3,000,000)	10,650,000
Proceeds from issuance of stock	-	78,800	-
Repurchase and cancellation of treasury stock	(748,700)	(3,695,100)	-
Net cash provided by (used in) financing activities	27,251,300	(6,616,300)	10,650,000
Net increase in cash and cash equivalents	30,249,900	370,700	3,958,600
Cash and cash equivalents, beginning of year	48,263,000	47,892,300	43,933,700
Cash and cash equivalents, end of year	$78,512,900	48,263,000	47,892,300

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Petroleum Development Corporation (PDC) and its wholly owned subsidiaries, Riley Natural Gas (RNG) and PDC Securities Incorporated. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in limited partnerships under the proportionate consolidation method. Under this method, the Company's 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 four business segments. The segments are drilling and development, natural gas marketing, oil and 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, Colorado and Kansas.

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

Property acquisition costs are capitalized when incurred. Geological and geophysical costs and delay rentals are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered economically producible reserves. If reserves are not discovered, such costs are expensed as dry holes. Development costs, including equipment and intangible drilling costs related to both producing wells and developmental dry holes, are capitalized.

(Continued)

Unproved properties or leases are written-off to expense when it is determined that they will expire or be abandoned.

Costs of proved properties, including leasehold acquisition, exploration and development costs and equipment, are depreciated or depleted by the unit-of-production method based on estimated proved developed oil and gas reserves.

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds or salvage value, is credited or charged to income. Upon retirement of a partial unit of property, the procceds are charged to accumulated depreciation and depletion.

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. The Company adopted SFAS No. 144 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 in 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)

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

In prior years, the Company had split dollar life insurance arrangements with certain executive officers. The arrangements were terminated during 2002. Under these arrangements, advances were made to these officers equal to the premiums due. The advances were collateralized by the cash surrender value of the policies. The Company recorded 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 and pipeline income consists of operation charges for well upkeep, maintenance, transportation of natural gas 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. 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 2003 or 2002.

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 probable that a forecasted transaction will not occur or management determines that designation of the derivative as a hedging instrument is no longer appropriate, hedge accounting will discontinue.

(Continued)

During 2000, the Company entered into an interest rate swap agreement which expires October 11, 2004 to reduce its exposure to variability from changing interest rates. The interest rate differential to be paid or received is 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:

	2003	2002	2001
Net income, as reported	$22,619,100	$9,284,800	$14,967,800
Deduct total stock-based employee compensation expense determined under fair-value-based method for all awards, net of tax	-	-	(486,100)
Pro forma net income	$22,619,100	$9,284,800	$14,481,700
Pro forma basic earnings per share	$1.45	$0.59	$0.89
Pro forma diluted earnings per share	$1.39	$0.58	$0.87

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, 2003, 2002 and 2001.

(Continued)

New Accounting Standards

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect on change in accounting principle on prior years of $198,600 (net of taxes of $121,700). During 2003 the liability has increased to $731,200 due to the additional wells purchased and drilled by the Company.

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. Disclosures required by this standard are included in the notes to these financial statements.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS no. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights (leases) associated with extracting oil and gas intangible assets in the balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify the historical cost of approximately $7,576,900 and $4,208,800 of mineral rights associated with undeveloped oil and gas properties and $15,485,500 and $10,898,700 of mineral rights associated with developed oil and gas properties as of December 31, 2003 and December 31, 2002, respectively, out of oil and gas properties and into a separate intangible mineral rights assets line item. The Company's total balance sheet, cash flows and results of operations would be not affected since such intangible assets would continue to be amortized and assessed for impairment.

(2) Notes and Accounts Receivable

Included in other assets are noncurrent accounts receivable as of December 31, 2003 and 2002, in the amounts of $819,700 and $445,600 less of an allowance for doubtful accounts of $338,100 and $445,600, respectively.

The allowance for doubtful current accounts receivable as of December 31, 2003 and 2002 was $149,200 and $78,900, 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 $80.0 million of which the Company has activated $60 million of the facility. The Company is required to pay a commitment fee of 1/4 percent on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2005.

(Continued)

As of December 31, 2003 and 2002 the outstanding balance was $53,000,000 and $25,000,000, 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, 2003 and 2002 the Company was in compliance with all financial covenants in the credit agreement.

At December 31, 2003, $10,000,000 of the outstanding balance was subject to an interest rate swap at a rate of 8.39%, $15,000,000 was subject to a 90-day LIBOR rate of 2.87%, $5,000,000 was subject to a 30-day LIBOR rate of 2.92%, and $23,000,000 was subject to a prime rate of 4.00%.

(4) Income Taxes

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

	2003	2002	2001
Current:			
Federal	$2,401,000	604,200	1,639,300
State	834,100	206,800	473,300
Total current income taxes	3,235,100	811,000	2,112,600
Deferred:			
Federal	7,802,800	2,461,200	3,898,600
State	1,067,900	525,200	103,800
Total deferred income taxes	8,870,700	2,986,400	4,002,400
Total income taxes	$12,105,800	3,797,400	6,115,000

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 35 percent in 2003 and 34 percent in 2002 and 2001 to pretax income as a result of the following:

	2003	2002	2001
Computed "expected" tax	$12,223,200	4,447,900	7,168,200
State income tax	1,362,000	483,100	380,900
Percentage depletion	(935,000)	(680,000)	(935,000)
Nonconventional source fuel credit	-	(491,500)	(1,184,700)
Effect of state rate change	-	-	556,500
Revision of prior estimate - Nonconventional Source Fuel Credit	(186,600)	-	-
Other permanent items, officers life insurance	(360,000)	-	-
Surtax exemption	(100,000)	-	-
Change in federal rate bracket	254,700	-	-
Other	(152,500)	37,900	129,100
	$12,105,800	3,797,400	6,115,000

(Continued)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2003 and 2002 are presented below:

	2003	2002
Deferred tax assets:		
Allowance for doubtful accounts	$ 189,500	199,300
Drilling notes	73,500	84,500
Alternative minimum tax credit carryforwards (Section 29)	437,400	2,055,500
Future abandonment	614,900	505,900
Deferred compensation	1,784,200	2,000,400
Other	27,700	40,600
Total gross deferred tax assets	3,127,200	4,886,200
Less valuation allowance	-	-
Deferred tax assets	3,127,200	4,886,200
Less current deferred tax assets (included in prepaid expenses)	(1,957,400)	(1,351,200)
Net non-current deferred tax assets	1,169,800	3,535,000
Deferred tax liabilities:		
Properties and equipment, principally due to differences in Depreciation and amortization	(23,842,200)	(16,730,500)
Total gross deferred tax liabilities	(23,842,200)	(16,730,500)
Net non-current deferred tax liability	(22,672,400)	(13,195,500)
Deferred income tax assets related to adoption of FASB 143	121,700	-
Deferred income tax assets related to AOCI	750,500	1,092,200
Net deferred tax liability	$(21,800,200)	(12,103,300)

At December 31, 2003, the Company has alternative minimum tax credit carryforwards (Section 29) of approximately $437,400 which are available to reduce future federal regular income taxes over an indefinite period.

Accumulated other comprehensive loss is net of tax of $750,500, $1,092,200 and $280,500 as of December 31, 2003, 2002 and 2001, respectively.

(5) Common Stock

Options

Options amounting to 185,000 shares were granted during 2001 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 was $3.70 per option. The fair value was estimated using the Black-Scholes option pricing model with the following assumptions for the 2001 grant: risk-free interest rate of 5.88%, expected dividend yield of 0%, expected volatility of 50.23% and expected life of 7 years.

(Continued)

	Number of Shares	Average Exercise Price	Range of Exercise Prices
Outstanding December 31, 2000	1,045,000	$3.95	1.125 - 6.125
Granted	185,000	$6.25	6.25 - 6.25
Outstanding December 31, 2001	1,230,000	$4.29	1.125 - 6.25
Exercised	(70,000)	$1.125	1.125 - 1.125
Outstanding December 31, 2002	1,160,000	$4.48	1.125 - 6.25
Granted	-	-	-
Exercised	-	-	-
Outstanding December 31, 2003	1,160,000	$4.48	1.125 - 6.25

As of December 31, 2003, there were 140,000 options outstanding and exercisable at the $1.125 exercise price which have a weighted average remaining contractual life of 1.9 years. Also as of December 31, 2003 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 4.9 years and weighted average exercise price of $4.95.

Common Stock Repurchase

On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. From inception of the program until December 31, 2003, the Company has repurchased 109,200 shares at an average price of $6.86. This program is scheduled to expire on December 31, 2004. The following activity has occurred since inception of the plan on March 13, 2003 until December 31, 2003.

Month of Purchase	March, 2003	April, 2003	September, 2003
Average Price paid per share	$6.08	$6.48	$11.15
Broker/Dealer	McDonald Investments	McDonald Investments	McDonald Investments
Number of Shares Purchased	46,500	49,900	12,800
Remaining Number of Shares to Purchase	738,500	688,600	675,800

(Continued)

Stock Repurchase Agreement

The Company has stock repurchase agreements with two 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. During the fourth quarter of 2003, the Company received $1,000,000 in life insurance proceeds which was recorded as other income from the death of the Company's Chief Financial Officer who had a stock repurchase agreement referred to above. The Company has not purchased shares from such executive's estate as of December 31, 2003.

(6) Employee Benefit Plans

The Company made 401-K Plan contributions of $305,500, $288,000 and $260,800 for 2003, 2002 and 2001, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $250,000, $200,000 and $200,000 to the plan in cash during 2003, 2002 and 2001, respectively.

During 2003, 2002 and 2001 the Company expensed $90,000 each year under a deferred compensation arrangement with certain executive officers of the Company. These amounts were paid during 2003 to such executive officers.

At December 31, 2002, the Company had recorded as other assets $501,000, related to the cash surrender value of the life insurance on certain executive officers, during 2003 such policies were distributed to the participants.

The Company has a deferred compensation arrangement covering certain executive officers of the Company as a supplemental retirement benefit. During 2003, 2002 and 2001 the Company expensed $181,900, $171,600, and $171,600, respectively, and has recorded a related liability in the amount $868,300 and $686,400 as of December 31, 2003 and 2002, respectively.

(7) Earnings Per Share

Basic earnings per share is based on the weighted average number of common shares outstanding of 15,659,591 for 2003, 15,866,363 for 2002 and 16,244,931 for 2001.

Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding of 16,297,793 for 2003, 16,143,414 for 2002 and 16,639,634 for 2001. Stock options are considered to be common stock equivalents and to the extent appropriate, have been added to the weighted average common shares outstanding.

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(8) Transactions with Affiliates

As part of its duties as well operator, the Company received $108,507,800 in 2003, $60,620,200 in 2002, and $71,802,700 in 2001 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 $8,410,900 and $3,917,900 includes amounts owed to affiliated partnerships as of December 31, 2003 and 2002, 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 $26,539,400 in 2003, $20,008,900 in 2002 and $16,072,500 in 2001 for various services and other reimbursements. Amounts due from the partnerships as of December 31, 2003 and 2002 were $929,600 and $1,028,000, and are included in notes and accounts receivable.

During 2003, 2002 and 2001, the Company paid $30,000, $51,800 and $30,100, respectively, to the Corporate Secretary's (former Board Member) 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 accounted for 10.3%, 10.8% and 13.1% of total revenues in 2003, 2002 and 2001, 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 2003, 2002 or 2001.

Substantially all of the Company's drilling programs contain a repurchase provision where Investing Partners may request the Company to purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are requested by the investors, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $4.8 million. The Company has adequate liquidity to meet this obligation. During 2003, the Company paid $266,500 under this provision for the repurchase of partnership units.

The Company's drilling programs formed since 1996 contain a performance standard which states that if certain performance levels are not met, the Company must remit a payment equal to one-half of its share of revenue from such partnership to the investing partners. During 2003, 2002, and 2001 the Company paid partnerships a total of $385,400, $198,500 and $287,200, respectively in accordance with the provision.

During the fourth quarter of 2003, the Company recorded a liability in accordance with the death benefit of the employment contract of the Company's Chief Financial Officer in the amount of $852,700.

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

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(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 and office printing and copying equipment. The future minimum lease payments under these non-cancellable operating leases as of December 31, 2003 are as follows:

Year	Lease Amount
2004	$ 366,300
2005	211,000
2006	97,300
2007	90,600
2008	68,000
	$833,200

The Company's share of this lease expense for operating leases for the years ended December 31, 2003, 2002 and 2001 was $574,700, $660,700 and $693,000, respectively.

(11) Supplemental Disclosure of Cash Flows

The Company paid $1,274,003, $1,290,400 and $1,173,100 for interest in 2003, 2002 and 2001, respectively. The Company paid income taxes in 2003, 2002 and 2001 in the amounts of $3,649,600, $175,000 and $2,830,000, respectively.

(12) Acquisitions of Oil and Gas Properties

During the second quarter of 2003, the Company purchased 166 wells in the Denver Julesburg Basin in northeastern Colorado from Williams Production RMT Company for $28 million. The Company estimates the acquisition included approximately 22.6 billion cubic feet (Bcf) of proved developed producing (PDP) and 3.4 Bcf of proved developed non-producing reserves (PDNP), all of which is natural gas. The acquired property may also include up to 150 additional locations subject to approval of revised spacing from the State of Colorado.

During the fourth quarter of 2003, the Company purchased from one of its joint venture partners in the Denver-Julesburg Basin in Weld County, Colorado approximately 3.1 billion cubic feet equivalent (Bcfe) of proved developed producing reserves from interests in 20.6 net wells (230 gross) and 1.8 Bcfe of proved developed non-producing reserves from interests in 17 net wells (183 gross). The purchase price was $5.2 million which also included over 30 additional drilling locations.

During the fourth quarter of 2003, the Company purchased 97 gross wells (73 net) wells in the Denver-Julesburg Basin located in northeast Colorado and northwestern Kansas for $6.0 million. This purchase adds approximately 4.5 billion cubic feet equivalent (Bcfe) of proved developed producing and proved developed non-producing reserves to the Company's oil and gas reserves along with 100,000 acres of oil and gas leases.

(Continued)

(13) Derivative Financial Instruments

The futures and option contracts hedge forecasted 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. On adoption of this Statement on January 1, 2001, the Company recorded a net transition adjustment of $(12,079,100) (net of related income tax benefit of $8,052,700) which was recorded in accumulated other comprehensive income (AOCI). 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 forecasted transactions and had a total estimated fair value of $(1,178,900) (net of tax) on December 31, 2003 and a total estimated fair value of $(1,782,000) (net of tax) on December 31, 2002.

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

December 31, 2003	Amount (mmbtu)	Fair Value	Fair Value net of tax
Futures contracts			
Marketing activities	3,480,000	$(1,540,400)	$(941,200)
Production activities	99,100	(9,600)	(5,900)
	3,579,100	$(1,550,000)	$(947,100)
Option contracts			
Marketing activities	-	-	-
Production activities	3,289,000	$ 57,500	$ 35,100
	3,289,000	$ 57,500	$ 35,100
December 31, 2002			
Futures contracts			
Marketing activities	3,950,000	$(1,431,400)	$(887,400)
Production activities	280,000	(209,700)	(130,000)
	4,230,000	$(1,641,100)	$(1,017,400)
Option contracts			
Marketing activities	-	-	-
Production activities	2,950,400	$(337,200)	$(209,100)
	2,950,400	$(337,200)	$(209,100)

(Continued)

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 increases 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, 2003 RNG had entered into a series of natural gas future contracts stemming from its marketing activities. Total open futures contracts are for the sale of 2,660,000 Mmbtu of natural gas with a weighted average price of $4.58 Mmbtu resulting in a total contract amount of $12,174,100 and a fair market value of $(1,810,500) and for the purchase of 820,000 Mmbtu of natural gas with a weighted average price of $5.17 Mmbtu resulting in a total contract amount of $4,243,400 and a fair market value of $270,200. Open future contracts maturing in 2004 are for the sale of 2,060,000 mmbtu of natural gas with a weighted average price of $4.66 mmbtu resulting in a total contract amount of $9,594,200 and a fair market value of $(1,562,100) and for the purchase of 820,000 mmbtu of natural gas with a weighted average price of $5.17 mmbtu resulting in a total contract amount of $4,243,400 and a fair market value of $270,200. The maximum term over which RNG is hedging exposure to the variability of cash flows for commodity price risk is 25 months. There were no open option contracts stemming from RNG's marketing activities as of December 31, 2003. As of December 31, 2002, RNG had entered into a series of natural gas future contracts and option contracts stemming from its marketing activities. Open future contracts as of December 31, 2002 that matured in 2003 were for the sale of 3,210,000 mmbtu of natural gas with a weighted average price of $3.18 Mmbtu resulting in a total contract amount of $12,728,100 and a fair market value of $(1,912,200).

As of December 31, 2003, 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 2004 are for the sale of 53,300 Mmbtu of natural gas with a weighted average price of $5.40 Mmbtu resulting in a total contract amount of $288,000 and a fair market value of $(40,000) and for the purchase of 45,700 Mmbtu of natural gas with a weighted average price of $4.77 resulting in a total contract amount of $218,100 and a fair value of $30,400. Open option contracts maturing in 2004 are for the sale of 2,597,800 Mmbtu with a weighted average floor price of $4.29 Mmbtu and a fair value of $185,300 and 691,200 Mmbtu with a weighted average ceiling price of $5.23 Mmbtu and a fair value of $(127,800). The maximum term over which the Company is hedging exposure to the variability of cash flows for commodity price risk is 12 months. 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 as of December 31, 2002 that matured in 2003 were 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 as of December 31, 2002 that matured in 2003 were 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).

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2003 and 2002, cash in the amount of $1,866,400 and $2,760,500 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, 2003 and 2002, the Company was a party to an interest rate swap agreement expiring on October 11, 2004. The agreement requires the Company, on a quarterly basis, to make a fixed-rate interest payment of 6.89% plus its current LIBOR rate margin (+1.50% At December 31, 2003) on a $10,000,000 amount related to its outstanding line of credit.

(Continued)

The fair value of the interest rate swap agreement was $(436,800), $(266,900) net of tax at December 31, 2003 and $(896,000), $(555,000) net of tax at December 31, 2002. Current market pricing models were used to estimate fair value.

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

Changes in the fair value of natural gas futures contracts designated as hedging instruments and that effectively offset the variability of cash flows associated with anticipated sales of natural gas are reported in accumulated other comprehensive income (AOCI). These amounts subsequently are reclassified into gas purchases for RNG and gas sales for PDC when the related gas is sold and affects earnings. Changes in the fair value of the interest rate swap agreement are reclassified into interest expense monthly.

(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:

	Years Ended December 31,		
	2003	2002	2001
Property acquisition cost:			
Proved undeveloped properties	$ 6,167,800	1,892,700	3,670,500
Producing properties	33,946,600	240,000	75,700
Development costs	30,630,100	16,429,400	35,411,900
	$70,744,500	18,562,100	39,158,100

The proved reserves attributable to the development costs in the above table were 27,719,000 Mcf and 517,000 bbls for 2003, 19,607,000 Mcf and 130,000 bbls for 2002, and 23,896,000 Mcf and 715,000 bbls for 2001 (amounts unaudited). Of the above development costs incurred for the years ended December 31, 2003, 2002 and 2001 the amounts of $4,289,600, $2,699,500 and $7,026,900, 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.

(Continued)

(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:

	December 31, 2003	December 31, 2002
Proved properties:		
Tangible well equipment	$133,356,900	114,431,800
Intangible drilling costs	110,087,300	64,973,600
Undeveloped properties	7,576,900	4,208,800
Capitalized asset retirement cost	537,800	-
	251,558,900	183,614,200
Less accumulated depreciation, depletion and amortization	64,205,100	50,664,600
	$187,353,800	132,949,600

(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:

	Years Ended December 31, 2003	2002	2001
Revenue:			
Oil and gas sales	$47,021,600	22,857,100	25,887,900
Expenses:			
Production costs	10,212,500	6,407,900	6,012,400
Depreciation, depletion and amortization	12,997,600	11,149,000	9,665,300
	23,210,100	17,556,900	15,677,700
Results of operations for oil and gas producing activities before provision for income taxes	23,811,500	5,300,200	10,210,200
Provision for income taxes	8,262,600	1,538,400	2,834,900
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$ 15,548,900	3,761,800	7,375,300

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 using the Company's effective tax rate.

(Continued)

(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, 2003, 2002 and 2001. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

	Oil (BBLS)		
	2003	2002	2001
Proved developed and undeveloped reserves:			
Beginning of year	2,073,000	2,126,000	2,166,000
Revisions of previous estimates	533,000	124,000	(176,000)
Beginning of year as revised	2,606,000	2,250,000	1,990,000
New discoveries and extensions:			
Rocky Mountain Region	517,000	130,000	715,000
Dispositions to partnerships	(112,000)	(80,000)	(384,000)
Acquisitions:			
Rocky Mountain Region	307,000	-	-
Production	(289,000)	(227,000)	(195,000)
End of year	3,029,000	2,073,000	2,126,000
Proved developed reserves:			
Beginning of year	1,849,000	1,801,000	1,527,000
End of year	2,889,000	1,849,000	1,801,000

	Gas (MCF)		
	2003	2002	2001
Proved developed and undeveloped reserves:			
Beginning of year	128,851,000	118,608,000	118,640,000
Revisions of previous estimates	4,394,000	1,469,000	(8,694,000)
Beginning of year as revised	133,245,000	120,077,000	109,946,000
New discoveries and extensions:			
Rocky Mountain Region	27,719,000	19,607,000	23,896,000
Dispositions to partnerships	(4,410,000)	(4,792,000)	(9,263,000)
Acquisitions:			
Michigan Basin	265,000	4,000	-
Rocky Mountain Region	32,169,000	75,000	2,000
Appalachian Basin	722,000	342,000	112,000
Production	(8,712,000)	(6,462,000)	(6,085,000)
End of year	180,998,000	128,851,000	118,608,000
Proved developed reserves:			
Beginning of year	94,847,000	88,477,000	92,131,000
End of year	134,936,000	94,847,000	88,477,000

(Continued)

(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 of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

	As of December 31,		
	2003	2002	2001
Future estimated revenues	$1,088,415,000	$548,949,000	$317,515,000
Future estimated production costs	(250,735,000)	(143,878,000)	(98,538,000)
Future estimated development costs	(65,275,000)	(50,971,000)	(45,323,000)
Future estimated income tax expense	(265,707,000)	(105,876,000)	(50,360,000)
Future net cash flows	506,698,000	248,224,000	123,294,000
10% annual discount for estimated timing of cash flows	(289,408,000)	(149,755,000)	(76,855,000)
Standardized measure of discounted future estimated net cash flows	$217,290,000	$98,469,000	$46,439,000

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

	Years Ended December 31,		
	2003	2002	2001
Sales of oil and gas production, net of production costs	$(36,810,000)	$(16,449,000)	$(19,876,000)
Net changes in prices and production costs	162,422,000	143,574,000	(140,487,000)
Extensions, discoveries and improved recovery, less related cost	114,533,000	39,347,000	25,942,000
Dispositions to partnerships	(12,936,000)	(6,940,000)	(28,935,000)
Acquisitions	139,078,000	1,167,000	189,000
Development costs incurred during the period	30,630,000	16,429,000	35,412,000
Revisions of previous quantity estimates	21,388,000	3,318,000	(23,818,000)
Changes in estimated income taxes	(159,831,000)	(55,516,000)	30,622,000
Accretion of discount	(139,653,000)	(72,900,000)	62,751,000
	$118,821,000	$ 52,030,000	$(58,200,000)

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

(Continued)

(19) Business Segments (Thousands)

PDC's operating activities can be divided into four major segments: drilling and development, natural gas marketing, oil and gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. The Company owns an interest in approximately 2,500 wells from which it derives oil and gas working interests. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31, 2003, 2002 and 2001 is as follows:

	2003	2002	2001
REVENUES			
Drilling and Development	$71,841	57,149	76,291
Natural Gas Marketing	73,141	46,366	66,207
Oil and Gas Sales	47,022	22,857	25,888
Well Operations	7,348	6,116	5,604
Unallocated amounts (1)	3,499	2,854	3,133
Total	$202,851	135,342	177,123
SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and Development	$10,564	7,983	10,291
Natural Gas Marketing	689	174	458
Oil and Gas Sales	23,812	5,300	10,112
Well Operations	3,059	2,788	2,415
Unallocated amounts (2)			
General and Administrative expenses	(4,974)	(4,392)	(4,146)
Interest expense	(1,329)	(1,340)	(993)
Other (1)	3,103	2,569	2,946
Total	$ 34,924	13,082	21,083
SEGMENT ASSETS			
Drilling and Development	$62,546	31,279	36,202
Natural Gas Marketing	17,006	16,641	2,945
Oil and Gas Sales	204,849	145,591	139,920
Well Operations	11,602	10,706	11,975
Unallocated amounts			
Cash	800	1,736	422
Other	9,919	6,299	8,388
Total	$306,722	212,252	199,852
EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS			
Drilling and Development	$ 6,168	1,800	5,963
Natural Gas Marketing	-	4	-
Oil and Gas Sales	63,588	16,670	35,488
Well Operations	2,944	1,221	839
Unallocated amounts	342	82	371
Total	$ 73,042	19,777	42,661

(1) Includes interest on investments and partnership management fees in 2003, 2002 and 2001 and gain on sale of assets in 2003, 2002 and 2001 which are not allocated in assessing segment performance.

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

(Continued)

(20) Quarterly Financial Data (Unaudited)

Summarized quarterly financial data for the years ended December 31, 2003 and 2002, are as follows:

	2003				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$53,994,400	$42,192,500	$47,207,900	$59,456,200	$202,851,000
Cost of operations	45,125,800	33,836,200	37,648,600	45,013,400	161,624,000
Gross profit	8,868,600	8,356,300	9,559,300	14,442,800	41,227,000
General and administrative expenses	1,177,700	1,186,600	1,377,300	1,232,800	4,974,400
Interest expense	236,200	259,800	415,000	418,100	1,329,100
Income before income taxes	7,454,700	6,909,900	7,767,000	12,791,900	34,923,500
Income taxes	2,460,000	2,280,300	2,563,100	4,802,400	12,105,800
Net income before cumulative effect of change of change in accounting principle	4,994,700	4,629,600	5,203,900	7,989,500,	22,817,700
Cumulative effect of change in accounting principle (net of taxes)	(198,600)	-	-	-	(198,600)
Net income	$ 4,796,100	$ 4,629,600	$ 5,203,900	$ 7,989,500	$22,619,100
Basic earnings per share before accounting change	$ .32	$ .29	$ .33	$.52	$1.46
Cumulative effect of change in accounting principle	(.01)	.00	.00	.00	(.01)
Basic earnings per share	$ .31	$ .29	$ .33	$.52	$1.45
Diluted earnings per share before accounting principle	$ .31	$ .29	$ .31	$.49	$1.40
Cumulative effect of change in accounting principle	(.01)	.00	.00	.00	(.01)
Diluted earnings per share	$ .30	$ .29	$ .31	$.49	$1.39

	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	30,644,300	28,590,800	25,557,500	31,735,400	116,528,000
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	239,300	355,900	399,800	344,800	1,339,800
Income before income taxes	4,226,600	3,494,800	1,121,400	4,239,400	13,082,200
Income taxes	1,297,600	1,072,900	232,400	1,194,500	3,797,400
Net income	$2,929,000	$ 2,421,900	$ 889,000	$ 3,044,900	$ 9,284,800
Basic earnings per share	$ .18	$ .15	$ .06	$ .20	$ .59
Diluted earnings per share	$ .18	$ .15	$ .05	$ .20	$ .58

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, 2003, 2002 and 2001

Column A Description	Column B Balance at Beginning of Period	Column C Additions, Charged to Costs and Expenses	Column D Deductions	Column E Balance at End of Period
Allowance for doubtful accounts deducted from accounts and notes receivable in the Balance sheet				
2003	$524,500	$ -	$ 37,200	$487,300
2002	$524,500	$ -	$ -	$524,500
2001	$524,500	$ -	$ -	$524,500