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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

• ANNUAL REPORT PURSUANT TO SECTION 13 or 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 1999

Commission File Number 0-7246

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

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

Nevada
(State or other jurisdiction of incorporation or organization)

95-2636730

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. [ ]

As of March 15, 2000, 15,982,376 shares of the Registrant's Common Stock were issued and outstanding, and the aggregate market value of such shares held by non-affiliates of the Registrant on such date was $45,985,012 (based on the last traded price of $4.00).

DOCUMENTS INCORPORATED BY REFERENCE

Document
Proxy

Item 1. Business

The Company is a regional independent energy company engaged primarily in the development, production and marketing of natural gas. The Company has grown primarily through drilling and development activities, the acquisition of natural gas producing wells and the expansion of its natural gas marketing activities. As of December 31, 1999, the Company operated approximately 1,800 wells located in the Appalachian and Michigan Basins and the Rocky Mountain Region, and had net proved reserves of 101 Bcf of natural gas. The Company's wells currently produce an aggregate of approximately 37,000 Mcf of natural gas per day, of which the Company's share is approximately 14,500 Mcf.

The majority of the wells operated by the Company are located in the West Virginia and Pennsylvania portions of the Appalachian Basin. The Appalachian Basin is characterized by shallow developmental wells, which generally have provided highly predictable drilling success rates. In addition, because wells drilled in the Appalachian Basin are closer to the large demand centers for natural gas in the northeastern United States, natural gas from this area has historically commanded a price premium relative to natural gas produced in areas such as the Gulf Coast and Mid-Continent regions of the United States. In 1997, the Company commenced drilling in the Antrim shale formation of the Michigan Basin and through December 31, 1999, had drilled 183 wells in this area. In 1999 in addition to its drilling activities, the Company purchased natural gas producing properties. In December 1999, the Company purchased 53 net wells in Colorado.

The Company owns Riley Natural Gas (RNG), an Appalachian Basin 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 small 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 reduce the financial impact on the Company of changes in the price of natural gas.

Since 1984, the Company has sponsored limited partnerships formed to engage in drilling operations. The Company typically retains a 20% ownership interest in these drilling limited partnerships. In 1999, the Company raised $36.1 million through four public drilling partnerships, making it the sponsor of the largest public oil and gas partnership program in the United States in that year. 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.

Industry Overview

Natural gas is the second largest energy source in the United States, after liquid petroleum. The 22 Tcf of natural gas consumed in 1999 represented approximately 23% of the total energy used in the United States. Natural gas is consumed in the United States as follows: 46% by industrial end-users as feedstock for products such as plastic and fertilizer or as the energy source for producing products such as glass; 21% and 14% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; 15% by utilities for the generation of electricity; and the remainder for transportation purposes.

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

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

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

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

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

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

As local supplies of natural gas are inadequate to meet demand, 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 region. Appalachian Basin natural gas production enjoys two advantageous factors affecting price. First, the Appalachian Basin is characterized by shallow development gas wells that generally have provided highly predictable drilling success rates of 90% to 92%, which permits a more basic approach to drilling based on the geology unique to the area. Also, the natural gas industry in the Appalachian Basin benefits from its proximity to the northeastern United States.

In the early 1980's, natural gas companies began exploiting the northern portion of Michigan's lower peninsula, when certain favorable tax credits for natural gas development were enacted. The result of such development was new advances in drilling technology, which made natural gas drilling in this area profitable even after the expiration of these tax credits. In Michigan's lower peninsula, there is an abundance of shallow Antrim gas shale, which can provide significant reserves per well drilled. Additionally, this area is close to certain end-user markets, which has provided favorable premiums. With a current productive area of nearly 2.5 million acres, Michigan has been one of the most active areas for natural gas drilling in the United States over the past decade.

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 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. During 1998, the Company leased 39,500 acres of oil and gas development rights acres in Utah, and was investigating opportunities in several other areas. In 1999 the company drilled four unsuccessful exploratory wells, two in Moffatt County, Colorado and two in Carter County, Montana. In November and December 1999 the Company acquired drilling rights to 20 locations in the Wattenberg field in Weld County, Colorado and a 7,400 acre lease in the Grand Valley field in Garfield County, Colorado. Prior to the end of 1999, the Company had drilled five successful wells in the Wattenberg field and was prepared to drill its first Grand Valley test well. Wells in both areas are generally development wells.

Business Strategy

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

Expand drilling operations. The Company has had one of the most active drilling programs in the Northeast in the 1990's and will seek to continue to build on the experience developed. The Company drilled 178 wells in 1999, compared to 213 for the year of 1998. 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, 1999, the Company had 37,000 net undeveloped acres in the Michigan Basin, 28,430 net undeveloped acres in the Appalachian Basin and 88,020 net undeveloped acres in the Rocky Mountain Region. As drilling activity increases, the Company benefits as its fixed costs may be spread over a larger number of wells.

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

Pursue geographic expansion. The Company has a proven ability to drill and operate shallow natural gas wells successfully. There are a number of areas outside the Appalachian Basin where drilling and operating characteristics are similar to those in Appalachia. For example, since 1996, the Company expanded into the Michigan Basin, which permitted the Company to leverage its expertise developed in the Appalachian Basin because of the similarities in methods of drilling, depth, equipment and operations. Moreover, reserves and production levels of two to three times that of Appalachian levels for a similar investment more than offset higher expected operating costs. The Company's Colorado development projects also build on our shallow gas well operating experience. The Company will continue to evaluate opportunities to expand geographically on an ongoing basis.

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

Expand strategic relationships. By managing drilling programs for itself and other investors, the Company is able to share administrative, overhead and other costs with its partners, reducing costs for both. The Company also is able to maintain a larger and more capable geology and engineering staff than would be possible without partners. Other benefits from these associations include greater buying power for drilling services and materials, larger amounts of natural gas available to market, profits to the Company from drilling and operating wells for partners, and greater awareness of the Company in the investment community.

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. The Company's team of professional geologists has decades of experience drilling successful, economically feasible natural gas wells. The geological team utilizes 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 stratigraphy that are used to predict areas with above-average prospects for economic development.

On the basis of these models, the geologists instruct the Company's land department to obtain available natural gas leaseholds in these prospective areas. These leases 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 12.5% royalty on gross production revenue in return for obtaining the leases. In some instances of particularly attractive properties, additional overriding royalty payments may be made to third parties or royalty owners. As of December 31, 1999, the Company had a total leasehold inventory of approximately 247,140 gross acres and 246,710 net acres. See--"Properties--Natural Gas Leases."

Drilling Activities

When prospects have been identified and leased, the Company develops these properties by drilling wells. In 1999, the Company drilled a total of 178 wells, of which 13 were dry holes. Typically, the Company will act as driller-operator for these prospects, entering into contracts with partnerships, including 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 1998 the Company purchased an 80% interest in 122 producing wells located in Pennsylvania from Pemco Gas, Inc. and a 100% working interest in 13 producing wells in Michigan, as well as certain well interests in its Company sponsored partnerships. In 1999, the Company purchased a 100% working interest in 53 producing wells in the D-J Basin of Colorado which added 3.6 Bcf of natural gas and 370,000 barrels of oil to the Company's reserves. Also purchased in 1999 were certain well interests in its Company sponsored partnerships.

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,				
	1999	1998	1997	1996	1995
Production(1):					
Oil(MBbls)	8	8	9	7	11
Natural Gas (MMcf)	3,451	2,453	1,810	1,495	1,336
Equivalent MMcfs(2)	3,499	2,501	1,864	1,537	1,402
Average sales price:					
Oil (per Bbl)	$18.75	$10.61	$16.10	$16.35	$15.80
Natural gas (per Mcf)	$2.46	$2.46	$2.88	$3.04	$1.75
Average production cost (lifting cost) per equivalent Mcf(3)	$0.69	$0.61	$0.65	$0.63	$0.53

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

Well Operations

The Company currently operates approximately 1,538 natural gas wells in the Appalachian Basin, 200 wells in the Michigan Basin and 58 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 48% ownership interest in the wells it operates. Currently these wells produce an aggregate of about 37,000 Mcf of natural gas per day, including the Company's share of 14,500 Mcf per day.

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

Transportation

Natural gas wells are connected by pipelines to natural gas markets. Over the years, the Company has developed extensive gathering systems in 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 producers 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.

The Company has an Ohio subsidiary, Paramount Natural Gas Company ("PNG"), which commenced operations in October 1992 as a regulated Ohio distribution utility. As a utility, PNG has been able to connect new customers, and the Company is able to compete for the natural gas markets of these customers by transporting natural gas through the PNG system. The majority of PNG's throughput is attributable to natural gas transported for the Company and industrial customers for a transportation tariff, with the balance being sales to residential, commercial and industrial customers.

Item 2. Properties

Drilling Activity

The following table summarizes the Company's development drilling activity for the years ended December 31, 1995, 1996, 1997, 1998 and 1999. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. The Company's exploratory wells drilled in the past five years consist of one dry hole (0.19 net) drilled in 1998 and five dry holes (2.44 net) drilled in 1999.

	Development Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
1995	72	13.40	64	11.80	8	1.60
1996	97	17.44	92	16.46	5	.98
1997	168	40.72	158	38.00	10	2.72
1998	212	56.99	201	54.22	11	2.77
1999	173	54.64	165	53.10	8	1.54
Total	722	183.19	680	173.58	42	9.61

Summary of Productive Wells

The table below shows the number of the Company's productive gross and net wells at December 31, 1999.

	WELLS			
	Gas		Oil	
Location	Gross	Net	Gross	Net
Colorado	58	53.78	-	-
Michigan	199	97.67	1	.80
Ohio	16	7.19	5	2.34
Pennsylvania	527	164.26	-	-
Tennessee	1	0.71	39	15.87
West Virginia	944	523.94	6	2.58
Total	1,745	847.55	51	21.59

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 101,245,000 Mcf of natural gas and 1,154,000 Bbls of oil at December 31, 1999; 80,819,000 Mcf of natural gas and 29,000 Bbls of oil at December 31, 1998; and 57,243,000 Mcf of natural gas and 45,000 Bbls of oil at December 31, 1997.

The Company's approximate net proved developed reserves were estimated, by Wright & Company to be 82,628,000 Mcf of natural gas and 798,000 Bbls of oil at December 31, 1999; 64,562,000 Mcf of natural gas and 29,000 Bbls of oil at December 31, 1998; and 42,411,000 Mcf of natural gas and 45,000 Bbls of oil at December 31, 1997.

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, 1999. 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 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 in 1999, 1998 and 1997 to be $58.5 million as of December 31, 1999, $30.2 million as of December 31, 1998 and $27.9 million as of December 31, 1997. These amounts are based on year-end prices at the respective dates. The values expressed are estimates only, and may not reflect realizable values or fair market values of the natural gas and oil ultimately extracted and recovered. The standardized measure of discounted future net cash flows may not accurately reflect proceeds of production to be received in the future from the sale of natural gas and oil currently owned and does not necessarily reflect the actual costs that would be incurred to acquire equivalent natural gas and oil reserves.

Net Proved Natural Gas and Oil Reserves

The proved reserves of natural gas and oil of the Company as estimated by Wright & Company at December 31, 1999 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, 1999 to December 31, 1999, all of which are located within the United States, is shown below:

	Natural Gas (Mcf)
Proved developed and undeveloped reserves:	
Beginning of year (January 1, 1999)	80,819,000
Revisions of previous estimates	(4,475,000)
Beginning of year as revised	76,344,000
New discoveries and extensions	24,781,000
Dispositions, to partnerships	(8,774,000)
Acquisitions	12,345,000
Production	(3,451,000)
End of period (December 31, 1999)	101,245,000
Proved developed reserves:	
Beginning of year (January 1, 1999)	64,562,000
End of period (December 31, 1999)	82,628,000

	Oil (Bbls)
Proved developed and undeveloped reserves:	
Beginning of year (January 1, 1999)	29,000
Revisions of previous estimates	67,000
Beginning of year as revised	96,000
New discoveries and extensions	404,000
Dispositions	-
Acquisitions	662,000
Production	(8,000)
End of period (December 31, 1999)	1,154,000
Proved developed reserves:	
Beginning of year (January 1, 1999)	29,000
End of period (December 31, 1999)	798,000

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, 1999 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.

	December 31, 1999
Future estimated cash flows	$307,816,000
Future estimated production and development costs	(129,557,000)
Future estimated income tax expense	(39,930,000)
Future net cash flows	138,329,000
10% annual discount for estimated timing of cash flows	(79,875,000)
Standardized measure of discounted future estimated net cash flows	$ 58,454,000

The followi ng table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows from January 1, 1999 through December 31, 1999:

Sales of oil and natural gas production, net of production costs	$(6,206,000)
Net changes in prices and production costs	29,547,000
Extensions, discoveries and improved recovery, less related cost	39,653,000
Dispositions to partnerships	(6,152,000)
Acquisitions	31,915,000
Development costs incurred during the period	17,168,000
Revisions of previous quantity estimates	(4,944,000)
Changes in estimated income taxes	(19,608,000)
Changes in discount	(39,463,000)
Changes in production rate (timing) and other	(13,650,000)
	$ 28,260,000

The foregoing data 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.

Natural Gas Leases

The following table sets forth, as of December 31, 1999, the acres of developed and undeveloped natural gas and oil properties in which the Company had an interest, listed alphabetically by state.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Colorado	2,080	2,080	7,600	7,600
Michigan	27,500	27,500	37,000	37,000
Montana	-	-	22,000	22,000
Ohio	740	740	500	500
Pennsylvania	8,700	8,700	19,000	19,000
Tennessee	5,400	5,400	-	-
Utah	-	-	58,420	58,420
West Virginia	49,000	48,840	9,200	8,930
Total	93,420	93,260	153,720	153,450

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 Company's properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens which the Company believes do not materially interfere with the use of or affect the value of such properties.

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. No customer accounted for more than 10.0% of total revenues in 1999. One customer, Hope Gas, Inc., a regulated public utility ("Hope Gas"), accounted for 12.6% of the Company's revenues from oil and gas sales (5.4% of total revenues) in 1998 and 26.6% of the Company's revenues from oil and gas sales (12.0% of total revenues) in 1997. The Company and Hope Gas were parties to a Pipeline Purchase Agreement, pursuant to which agreement the Company delivered to Hope Gas, upon demand, minimum quantities of natural gas (4,500 dth per day delivered directly to Hope Gas's pipelines and 11,000 dth per day for total deliveries including both direct and transferred volumes). The Company and Hope Gas were also parties to a Master Gas Purchase Agreement, which expired on May 31, 1999, pursuant to which the Company offered to Hope Gas all volumes of natural gas available at specific points of delivery, up to the minimum delivery requirements of the Pipeline Purchase Agreement. No other single purchaser of the Company's natural gas accounted for 10% or more of the Company's total revenues during 1999, 1998 or 1997.

At December 31, 1999, natural gas produced by the Company sold at prices per Mcf ranging from $0.90 to $4.35, depending upon well location, the date of the sales contract and whether the natural gas was sold in interstate or intrastate commerce. The weighted net average price of natural gas sold by the Company during 1999 was $2.46 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 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.

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, as natural gas markets are deregulated, 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 alterative 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.

In 1996, the Company acquired RNG, an Appalachian Basin natural gas marketing company that specializes in the acquisition and aggregation of Appalachian Basin gas production. The owner/managers and employees of RNG joined the Company, and RNG's operations were relocated to the Company's headquarters. 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 the natural gas market in the Appalachian region. Such knowledge assists the Company in maximizing its prices as it markets natural gas from Company-operated wells. RNG and its management also brought to the Company specific knowledge and relationships with many producers in the Appalachian Basin region. Paramount Transmission Corporation ("PTC"), an Ohio subsidiary of the Company, focuses its efforts on the marketing of Ohio natural gas production to commercial and industrial end-users.

In West Virginia, Pennsylvania, Michigan and Colorado, the Company markets natural gas from its own wells and wells operated for its investment partnerships. 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. The contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a three- to 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 to coordinate fixed and variable priced purchases and sales and to "lock in" fixed prices from time to time for the Company's share of production. In order for future contracts to serve as effective hedges, there must be sufficient correlation to the underlying hedged transaction. While hedging can help provide price protection if spot prices drop, hedges can also limit upside potential.

Despite the measures taken by the Company to attempt to control price risk, the Company remains 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. As of December 31, 1999, there were 182 existing hedge positions representing 1,820,000 Mmbtu.

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 $36.1 million in subscriptions in 1999. Funds received pursuant to drilling contracts were $40.9 million in 1998 and $35.5 million in 1997. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 20% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. While funds were received by the Company pursuant to drilling contracts in the years indicated, the Company recognizes revenues from drilling operations on the percentage of completion method as the wells are drilled, rather than when funds are received. Most of the Company's drilling and development funds now are received from partnerships in which the Company serves as managing general partner. However, because wells produce for a number of years, the Company continues to serve as operator for a large number of unaffiliated parties. In addition to the partnership structure, the Company also utilizes joint venture arrangements for financing drilling activities.

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

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

The level of the Company's drilling and development activity is dependent upon the amount of subscriptions in its public drilling partnerships and investments from other partnerships or other joint venture partners. The use of partnerships and similar financing structures enables the Company to diversify its holdings, thereby reducing the risks to 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.

Oil Production

Before 1980, the Company generated a significant portion of its revenues from oil production. However, the Company made a strategic decision to concentrate its development efforts on natural gas production and most of the Company's current oil production is associated with natural gas production. The Company's current production of oil is from wells located in Tennessee, Ohio, West Virginia and Colorado. In 1999, its share of oil production is about 8,000 barrels. The Company's acquisition in December 1999 of 53 wells in Colorado, and ongoing development activities in Colorado and Michigan are resulting in a significant increase in oil production and reserves. At the end of 1999 oil was about 6% 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 wit h arrangements which are customary in the oil industry. No single purchaser of the Company's crude oil accounted for 10% or more of the Company's revenues from oil and gas sales in 1999, 1998 or 1997 . At December 31, 1999, oil produced by the Company sold at prices ranging from $21.75 to $24.57 per barrel, depending upon the location and quality of oil. In 1999, the weighted net average price per barrel of oil sold by the Company was $18.75.

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.

Governmental Regulation

The Company's business and the n atural 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 Natural Gas Exploration and Production

The Company's 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 establish maximum rates of production from 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 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 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 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 benefitted 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 he adversely affected.

The Co mpany 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 1999 were not significant in relation to operating costs and the Company expects no material change in 2000. Environmental regulations have had no materially adverse effect on the Company's operations to date, but no assurance can be given that environmental regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on the Company's business, financial condition or results of operations.

As a matter of corporate policy and commitment, the Company attempts to minimize the adverse environmental impact of all its operations. For example, during 1999, the Company was one of the most active drilling companies in the northeast. Even with this level of activity, the Company was able to maintain a high level of environmental sensitivity. During the 1990's, the Company has been a nine-time recipient of the West Virginia Department of Environmental Protection's top award in recognition of the quality of the Company's environmental and reclamation work in its drilling activities.

Utility Regulation

PNG, which is an Ohio public utility, is subject to regulation by the Public Utilities Commission of Ohio in virtually all of its activities, including pricing and supply of services, addition of and abandonment of service to customers, design and construction of facilities, and safety issues.

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 believe s that its exploration, drilling and production capabilities and the experience of its management generally enable it to compete effectively. The Company encounters competition from numerous other 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 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 oil companies to increase their domestic natural gas exploration. Furthermore, competition among natural gas companies for favorable natural gas prospects can be expected to continue, and it is anticipated that the cost of acquiring natural gas 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 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, 1999, the Company had 91 employees, including 13 in finance, 7 in administration, 14 in exploration and development, 52 in production and 5 in natural gas marketing. The Company's engineers, supervisors and well tenders are generally responsible for the day -to-day operation of wells and pipeline systems. In addition, the Company retains subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites. The Company's employees act as supervisors of the subcontractors.

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

Facilities

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

Item 3. Legal Proceedings

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

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

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

PART II

Item 5. Market for the Company's Common Stock and Related Security Holder Matters

The common stock of the Company is traded in the over-the-counter 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 the National Quotation Bureau Incorporated. These quotations represent inter-dealer prices without retail markups, markdowns, commissions or other adjustments and may not represent actual transactions.

	High	Low
1998		
First Quarter	6 5/8	4 1/8
Second Quarter	6 1/2	4 13/16
Third Quarter	5 1/2	3 5/16
Fourth Quarter	5 3/8	2 15/16
1999		
First Quarter	3 15/16	2 7/8
Second Quarter	4 11/16	3 5/16
Third Quarter	5 3/8	4 3/16
Fourth Quarter	4 13/16	3 23/32

As of December 31, 1999, there were approximately 1,349 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 Financial Data (1)

	1999	1998	1997	1996	1
enues					
l and gas well illing erations	$42,115,600	$40,447,100	$34,405,400	$18,698,200	$13,941,
l and gas sales	46,988,100	35,560,300	33,390,200	26,051,100	4,150,
ll operations ncome	5,314,500	4,581,000	4,509,300	3,928,800	3,750,
ner income	2,392,400	2,385,200	1,573,100	935,600	504,
Total	$96,810,600	$82,973,600	$73,878,000	$49,613,700	$22,346,
ts and Expenses excluding nterest and epreciation, epletion and mortization)	$82,496,500	$71,094,900	$61,219,600	$42,274,100	$18,042,
erest Expense	$ 182,400	$ -	$ 315,900	$ 380,000	$ 319,
reciation, oletion and ortization	$ 4,031,200	$ 3,253,600	$ 2,660,300	$ 2,309,600	$ 2,152,
Income	$ 7,824,300	$ 6,658,000	$ 7,586,800	$ 3,549,400	$ 1,481,
ic earnings common share	$.50	$.43	$ .67	$ .34	$ .13
uted earnings share	$.48	$.41	$ .67	$ .34	$ .13
rage Common and mmon Equivalent ares Outstanding ring the Year	16,286,852	16,338,298	12,540,165	11,542,315	11,611,

	December 31,				
	1999	1998	1997	1996	1
al Assets	$132,083,600	$111,409,000	$98,411,600	$63,604,200	$40,620,
king Capital	$ (2,503,900)	$ 1,633,400	$16,483,200	$(2,357,200)	$(1,519,
g-Term Debt, cluding current turities	$ 9,300,000	$ -	$ -	$ 5,320,000	$ 2,500,
ckholders' uity	$70,724,900	$ 62,746,700	$55,766,100	$23,072,500	$19,920,

See Consolidated Financial Statements elsewhere herein.

n 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 incident to the exploration for, acquisition, development and marketing of oil and gas, and it can give no assurance that its estimates and expectations will be realized. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to, changes in production volumes, worldwide demand, and commodity prices for petroleum natural resources; the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and gas reserves; risks incident to the drilling and operation of oil and gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; the effect of hedging activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-K.

Results of Operations

Year Ended December 31, 1999 Compared with December 31, 1998

Revenues. Total revenues for the year ended December 31, 1999 were $96.8 million compared to $83.0 million for the year ended December 31, 1998, an increase of approximately $13.8 million, or 16.6%. Drilling revenues for the year ended December 31, 1999 were $42.1 million compared to $40.4 for the year ended December 31, 1998, an increase of approximately $1.7 million, or 4.2%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in drilling funds from the Company's public drilling programs. Oil and gas sales for the year ended December 31, 1999 were $47.0 million compared to $35.6 million for the year ended December 31, 1998, an increase of approximately $11.4 million, or 32.0%. Such increase was due to the natural gas marketing activities of RNG, along with increased production from the Company's producing properties. The increase in production from the Company's producing properties from 1998 to 1999 was 40.7%. Well operations and pipeline income for the year ended December 31, 1999 was $5.3 million compared to $4.6 million for the year ended December 31, 1998, an increase of approximately $700,000 or 15.2%. Such increase resulted from an increase in the number of wells operated by the Company. Other income remained constant at $2.4 million for the years ended December 31, 1999 and 1998. However for the year ended December 31, 1999 a gain on the sale of oil and gas property offset the decrease in interest earned in 1999 compared to 1998 due to lower average cash balances.

Costs and expenses. Costs and expenses for the year ended December 31, 1999 were $86.7 million compared to $74.3 million for the year ended December 31, 1998, an increase of approximately $12.4 million, or 16.7%. Oil and gas well drilling operations costs for the year ended December 31, 1999 were $35.5 million compared to $35.0 million for the year ended December 31, 1998, an increase of approximately $500,000 or 1.4%. Such increase resulted from additional expenses due to increased drilling activity. Oil and gas purchases and production costs for the year ended December 31, 1999 were $44.2 million compared to $33.6 million for the year ended December 31, 1998, an increase of approximately $10.6 million, or 31.5%. Such increase was due primarily to natural gas marketing activities of RNG along with production costs associated with the increased production from the Company's producing properties. General and administrative expenses for the year ended December 31, 1999 were $2.8 million compared to $2.5 million for the year ended December 31, 1998, an increase of approximately $300,000. Depreciation, depletion and amortization costs for the year ended December 31, 1999 were $4.0 million compared to $3.3 million for the year ended December 31, 1998, an increase of approximately $700,000 or 21.2%. Such increase was due to the increased amount of investment in oil and gas properties owned by the Company. Interest costs were $182,000 for the year ended December 31, 1999 as the Company utilized its credit agreement during the third and fourth quarters of 1999.

Net income. Net income for the year ended December 31, 1999 was $7.8 million compared to $6.7 million for the year ended December 31, 1998, an increase of approximately $1.1 million or 16.4%.

Year Ended December 31, 1998 Compared with December 31, 1997

Revenues. Total revenues for the year ended December 31, 1998 were $83.0 million compared to $73.9 million for the year ended December 31, 1997, an increase of approximately $9.1 million, or 12.3%. Drilling revenues for the year ended December 31, 1998 were $40.4 million compared to $34.4 for the year ended December 31, 1997, an increase of approximately $6.0 million, or 17.4%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in drilling funds from the Company's public drilling programs. Oil and gas sales for the year ended December 31, 1998 were $35.6 million compared to $33.4 million for the year ended December 31, 1997, an increase of approximately $2.2 million, or 6.6%. Such increase was due primarily to the natural gas marketing activities of RNG, along with increased production from the Company's producing properties. This increase in production was offset in part by lower average sales prices from the Company's producing properties and decreased natural gas purchased for resale. Well operations and pipeline income for the year ended December 31, 1998 was $4.6 million compared to $4.5 million for the year ended December 31, 1997, an increase of approximately $100,000, or 2.2%. Such increase resulted from an increase in the number of wells operated by the Company. Other income for the year ended December 31, 1998 was $2.4 million compared to $1.6 million for the year ended December 31, 1997, an increase of approximately $800,000 or 50.0%. Such increase was due to management fees earned on higher volumes of drilling partnerships and interest earned on higher average cash balances.

Costs and expenses. Costs and expenses for the year ended December 31, 1998 were $74.3 million compared to $64.2 million for the year ended December 31, 1997, an increase of approximately $10.1 million, or 15.7%. Oil and gas well drilling operations costs for the year ended December 31, 1998 were $35.0 million compared to $28.0 million for the year ended December 31, 1997, an increase of approximately $7.0 million, or 25.0%. Such increase resulted from additional expenses due to increased drilling activity. Oil and gas purchases and production costs for the year ended December 31, 1998 were $33.6 million compared to $30.9 million for the year ended December 31, 1997, an increase of approximately $2.7 million, or 8.7%. Such increase was due primarily to natural gas marketing activities of RNG along with production costs associated with the increased production from the Company's producing properties, offset in part by lower volumes of gas purchased for resale by the Company. General and administrative expenses for the year ended December 31, 1998 were $2.5 million compared to $2.3 million for the year ended December 31, 1997, an increase of approximately $200,000. Depreciation, depletion and amortization costs for the year ended December 31, 1998 were $3.3 million compared to $2.7 million for the year ended December 31, 1997, an increase of approximately $600,000 or 18.5%. Such increase was due to the increased amount of investment in oil and gas properties owned by the Company. Interest costs were eliminated after the Company extinguished the balance on its bank credit line in November, 1997.

Net income. Net income for the year ended December 31, 1998 was $6.7 million compared to $7.6 million for the year ended December 31, 1997, a decrease of approximately $900,000, or 11.8%.

Year 2000 Issue

The Company experienced no known disruptions as a result of the year date change and intends to continue monitoring its critical systems at various other date changes during the Year 2000.

The Company expenditures for addressing Year 2000 issues were not material, nor does the Company expect to incur any significant costs addressing Year 2000 issues in the future.

Liquidity and Capital Resources

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

Sales volu mes of natural gas have continued to increase while natural gas prices fluctuate monthly. The Company's natural gas sales prices are subject to increase and decrease based on various market-sensitive indices. A major factor in the variability of these indices is the seasonal variation of demand for the natural gas, which typically peaks during the winter months. The volumes of natural gas sales are expected to continue to increase as a result of continued drilling activities and additional investment by the Company in oil and gas properties. The Company utilizes commodity-based derivative instruments (natural gas futures and option contracts traded on the NYMEX) as hedges to manage a portion of its exposure to this price volatility. The futures contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a three to twelve-month period.

The Company has a bank credit agreement with First National Bank of Chicago, which provides a borrowing base of $20.0 million, subject to adequate oil and natural gas reserves. As of December 31, 1999, the balance outstanding on the line of credit is $9.3 million. 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 December 31, 2002.

The Company closed four public drilling partnerships during 1999. The total amount received during 1999 was $36.1 million compared to $40.9 million for 1998. The Company closed its fourth program of 1999 on December 31, 1999 in the amount of $18.7 million and will drill the wells during the first quarter 2000. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 20% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

On January 29, 1999, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1996. The Company purhased approximately $1.8 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1999. The Company utilized capital received from its 1997 public stock offering to fund this purchase.

On December 15, 1999, the Company purchased all of the working interest in 53 producing wells in the D-J Basin of Colorado. The Company estimates that the purchase includes proved developed reserves of approximately 3.6 Bcf of natural gas and 370,000 barrels of oil or approximately 5.8 Bcf equivalent (Bcfe), along with another 3.0 Bcfe of net development drilling locations. The total acquisition cost for the wells and locations was $5.2 million. The Company utilized part of its existing line of credit to fund the transaction. The effective date of the transaction was December 1, 1999.

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.

New Accounting Standards

Statement of Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), was issued by the Financial Accounting Standards Board in June, 1998. SFAS No. 133 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. SFAS No. 133 is effective for years beginning after June 15, 2000; however, early adoption is permitted. On adoption, the provisions of SFAS No. 133 must be applied prospectively. At the present time, the Company cannot determine the impact that SFAS No. 133 will have on its financial statements upon adoption, as such impact will be based on the extent of derivative instruments, such as natural gas futures and option contracts, outstanding at the date of adoption.

Item 7.a. 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, 1999 is $9,992,700 with an average interest rate of 3.63 percent. As of December 31, 1999, the Company has long-term debt of $9,300,000 of which $6,300,000 is at a prime interest rate of 8.5% and $3,000,000 at a LIBOR interest rate of 7.73%.

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. 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. As a result, while these hedging arrangements are structured to reduce the Company's exposure to decreases in price associated with the hedging 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, 1999, PDC had entered into a series of natural gas future contracts and options contracts. Open future contracts maturing in 2000 are for the purchase of 1,820,000 MMBtu of natural gas with a weighted average price of $2.3725 MBtu resulting in a total contract amount of $4,317,950, and a fair market value of $350,500.

PART III

Item 8. Financial Statements and Supplementary Data:

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

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

None.

Item 10. Directors and Executive Officers of the Company

Directors and Officers of the Company

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

Name	Age	Positions and Offices Held
James N. Ryan	68	Chairman, Chief Executive Officer and Director
Steven R. Williams	48	President and Director
Dale G. Rettinger	55	Chief Financial Officer, Executive Vice President, Treasurer and Director
Ersel E. Morgan	56	Vice President of Production
Thomas F. Riley	47	Vice President of Business Development
Eric R. Stearns	41	Vice President of Exploration and Development
Darwin L. Stump	44	Controller
Roger J. Morgan	72	Secretary and Director
Vincent F. D'Annunzio	47	Director
Jeffrey C. Swoveland	44	Director
Donald B. Nestor	50	Director

James N. Ryan served as President of the Company from 1969 to 1983 and has served as director of the Company since 1969. Mr. Ryan was elected Chairman and Chief Executive Officer of the Company in March 1983. Mr. Ryan focuses on capital formation through the Company's drilling partnerships.

Steven R. Williams has served as President and director of the Company since March 1983. Prior to joining the Company, Mr. Williams was employed by Exxon as an engineer from 1973 until 1979. A 1981 graduate of the Stanford Graduate School of Business, Mr. Williams was employed by Texas Oil and Gas Company as a financial analyst from 1981 until July 1982, when he joined Exco Enterprises as Manager of Operations, and served in that capacity until he joined the Company.

Dale G. Rettinger has served as Vice President and Treasurer of the Company since July 1980. Additionally, Mr. Rettinger has served as President of PDC Securities Incorporated since 1981. Mr. Rettinger was elected director in 1985 and appointed Chief Financial Officer in September 1997. Previously, Mr. Rettinger was a partner with KMG Main Hurdman, Certified Public Accountants, and served in that capacity from 1976 until he joined the Company.

Ersel E. Morgan has served as Vice President of Production of the Company since 1995. Prior to assuming this position, Mr. Morgan served as the Company's Manager of the Land and Operations groups from 1981 until 1993 and as Manager of Production of the Company from 1993 to 1995.

Thomas E. Riley has served as Vice President of Business Development of the Company since April 1996. Mr. Riley co-founded and has served as President of RNG since its inception in 1987 until the present. See "Certain Transactions."

Eric R. Stearns has served as Vice President of Exploration and Development of the Company since 1995. Mr. Stearns joined the Company in 1985 as a wellsite geologist and served as Manager of Geology from 1988 until 1995.

Darwin L. Stump has served as Controller of the Company since 1980. Previously, Mr. Stump was a senior accountant with Main Hurdman, Certified Public Accountants, having served in that capacity from 1977 until he joined the Company.

Roger J. Morgan, a director and Secretary of the Company since 1969, has been a member of the law firm of Young, Morgan & Cann, Clarksburg, West Virginia, for more than the past five years. Mr. Morgan is not active in the day-to-day business of the Company, but his law firm provides legal services to the Company.

Vincent F. D'Annunzio, a director since February 1989, has for more than the past five years served as President of Beverage Distributors, Inc. located in Clarksburg, West Virginia.

Jeffrey C. Swoveland, a director since March 1991, has been employed by Equitable Resources, an oil and gas production, marketing and distribution company, since 1994 and presently serves as Treasurer. Mr. Swoveland previously served as Vice President and a lending officer with Mellon Bank, N.A. from July 1989 until 1994.

Donald B. Nestor, elected as a director in March, 2000, is a Certified Public Accountant and a Partner in the CPA firm of Toothman Rice, P.L.L.C. and is in charge of the firm's Buckhannon, West Virginia office. Mr. Nestor has servied in that capacity for more than the past five years.

The Company's By-Laws provide that the directors of the Company shall be divided into three classes and that, at each annual meeting of stockholders of the Company, successors to the class of directors whose term expires at the annual meeting will be elected for a three-year term. The classes are staggered so that the term of one class expires each year. Mr Williams and Mr. Morgan are members of the class whose term expires in 2000; Mr. Ryan and Mr. D'Annunzio are members of the class whose term expires in 2001; and Mr. Rettinger and Mr. Swoveland are members of the class whose term expires in 2002. 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.

Item 11. Management Remuneration and Transactions

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 2000 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2000.

Item 12. Security Ownership of Certain Beneficial Owners and Management

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 2000 annual meeting of stockholders filed or to be filed with the Commission on or before April 30, 2000.

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.

PART IV

Item 14. 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/ James N. Ryan
James N. Ryan, Chairman

March 17, 2000

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/ James N. Ryan James N. Ryan	Chairman, Chief Executive Officer and Director	March 17, 2000
/s/ Steven R. Williams Steven R. Williams	President and Director	March 17, 2000
/s/ Dale G. Rettinger Dale G. Rettinger	Chief Financial Officer Executive Vice President, Treasurer and Director (principal financial and accounting officer)	March 17, 2000
/s/ Roger J. Morgan Roger J. Morgan	Secretary and Director	March 17, 2000

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Index to Financial Statements and Financial Statement Schedules

Independent Auditors' Report

The Stockholders and Board of Directors
Petroleum Development Corporation:

We have audited the consolidated financial statements of Petroleum Development Corporation and subsidiaries as listed in the accompanying index. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule as listed in the accompanying index. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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, 1999 and 1998, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1999, in conformity with generally accepted accounting principles. 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.

KPMG LLP

Pittsburgh, Pennsylvania
March 6, 2000

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 1999 and 1998

	1999	1998
Assets		
Current assets:		
Cash and cash equivalents (includes restricted cash of $614,300 and $156,200, respectively)	$29,059,200	34,894,600
Notes and accounts receivable	10,263,200	6,024,100
Inventories	577,600	702,400
Prepaid expenses	2,360,100	2,496,100
Total current assets	42,260,100	44,117,200
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	105,837,900	81,592,700
Pipelines	8,643,400	7,669,700
Transportation and other equipment	2,686,800	2,332,200
Land and buildings	1,181,000	1,152,700
	118,349,100	92,747,300
Less accumulated depreciation, depletion and amortization	31,207,300	27,356,700
	87,141,800	65,390,600
Other assets	2,681,700	1,901,200
	$132,083,600	111,409,000

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 1999 and 1998

	1999	1998
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 14,678,900	11,218,900
Accrued taxes	276,400	-
Other accrued expenses	2,643,700	1,959,900
Advances for future drilling contracts	25,137,400	28,320,800
Funds held for future distribution	2,027,600	984,200
Total current liabilities	44,764,000	42,483,800
Long-term debt	9,300,000	-
Other liabilities 3,160,600	2,233,500	
Deferred income taxes	4,134,100	3,945,000
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 15,737,795 and 15,510,762	157,400	155,100
Additional paid-in capital	32,071,000	31,873,100
Warrants outstanding	-	46,300
Retained earnings	38,496,500	30,672,200
Total stockholders' equity	70,724,900	62,746,700
	$132,083,600	111,409,000

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Income

Years Ended December 31, 1999, 1998 and 1997

	1999	1998	1997
Revenues:			
Oil and gas well drilling operations	$42,115,600	40,447,100	34,405,400
Oil and gas sales 46,988,100	35,560,300	33,390,200	
Well operations and pipeline income	5,314,500	4,581,000	4,509,300
Other income	2,392,400	2,385,200	1,573,100
	96,810,600	82,973,600	73,878,000
Costs and expenses:			
Cost of oil and gas well drilling operations	35,507,300	35,047,500	28,033,200
Oil and gas purchases and production Cost	44,188,200	33,556,900	30,867,600
General and administrative expenses	2,801,000	2,490,500	2,318,800
Depreciation, depletion and amortization	4,031,200	3,253,600	2,660,300
Interest	182,400	-	315,900
	86,710,100	74,348,500	64,195,800
Income before income taxes	10,100,500	8,625,100	9,682,200
Income taxes	2,276,200	1,967,100	2,095,400
Net income	$ 7,824,300	6,658,000	7,586,800
Basic earnings per common share	$.50	.43	.67
Diluted earnings per common and common equivalent share	$.48	.41	.61

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 1999, 1998 and 1997

Retained earnings	Common stock issued: Number of shares Total	Amount	Additional paid-in capital	Warrants out-standing	
Balance December 31, 1996	10,460,753	$104,600	6,540,500	-	16,4
Issuance of common stock:					
Stock offerings	4,577,500	45,800	24,903,600	46,300	
Exercise of employee stock options	207,505	2,100	96,700	-	
Amortization of stock award			12,300	-	
Net income	-	-	-	-	7,5
Balance December 31, 1997	15,245,758	$152,500	31,553,100	46,300	24,0
Issuance of common stock:					
Exercise of employee stock options 324,333	3,200	300,800	-	-	3
Amortization of stock award	-	-	12,200	-	
Repurchase and cancellation of treasury stock	(59,329)	(600)	(303,400)	-	
Income tax benefit from the exercise of stock options	-	-	310,400	-	
Net income -	-	-	-	6,658,000	6,0
Balance December 31, 1998	15,510,762	$155,100	31,873,100	46,300	30,0
Issuance of common stock:					
Exercise of employee stock options	324,333	3,200	300,800	-	
Amortization of stock award	-	-	12,200	-	
Repurchase and cancellation of treasury stock	(97,300)	(900)	(303,100)	-	
Income tax benefit from the exercise of stock options	-	-	141,700	-	
Warrants expired	-	-	46,300	(46,300)	
Net income	-	-	-	-	7,8
Balance December 31, 1999	15,737,795	$157,400	32,071,000	-	38,4

See accompanying notes to consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years Ended December 31, 1999, 1998 and 1997

	1999	1998	19
Cash flows from operating activities:			
Net income	$ 7,824,300	6,658,000	7,586,8
Adjustment to net income to reconcile to cash provided by operating activities:			
Deferred income taxes	108,900	244,000	107,7
Depreciation, depletion and amortization	4,031,200	3,253,600	2,660,3
(Gain) Loss from sale of assets	(501,800)	18,700	(39,6
Disposition of leasehold acreage	618,100	196,200	187,2
Amortization of stock award	12,200	12,200	12,3
(Increase) decrease in notes and accounts receivable	(4,239,100)	(1,100,700)	1,772,6
Decrease (increase) in inventories	124,800	(404,500)	269,3
Decrease (increase) in prepaid expenses	312,600	(600)	(998,2
(Increase) in other assets	(750,900)	(911,200)	(453,0
Increase in accounts payable and accrued expenses	5,347,300	1,304,000	1,298,4
(Decrease) increase in advances for future drilling contracts	(3,183,400)	5,029,200	4,894,6
Increase (decrease) in funds held for future distribution	1,043,400	(675,500)	795,7
Total adjustments	2,923,300	6,965,400	10,507,3
Net cash provided by operating activities	10,747,600	13,623,400	18,094,1
Cash flows from investing activities:			
Capital expenditures	(27,758,200)	(26,629,700)	(13,675,1
Proceeds from sale of leases	1,224,200	1,283,600	1,710,9
Proceeds from sale of fixed assets	651,000	56,300	87,6
Net cash used in investing activities	(25,883,000)	(25,289,800)	(11,876,6
Cash flows from financing activities:			
Proceeds from debt	9,300,000	-	-
Proceeds from issuance of stock	-	-	25,048,1
Retirement of debt	-	-	(5,320,0
Net cash provided by financing activities	9,300,000	-	19,728,1
Net (decrease) increase in cash and cash equivalents	(5,835,400)	(11,666,400)	25,945,6
Cash and cash equivalents, beginning of year	34,894,600	46,561,000	20,615,4
Cash and cash equivalents, end of year	$ 29,059,200	34,894,600	46,561,0

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

The Company is involved in three business segments. The segments are drilling and development, natural gas sales and well operations. (See Note 18)

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 and Colorado.

Cash Equivalents

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

Inventories

Inventories of well equipment, parts and supplies are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased in excess of deliveries to customers and is recorded at the lower of cost or market.

Oil and Gas Properties

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

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

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

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

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

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

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

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. These assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. An impairment loss based on estimated fair value is recorded when the review indicates that the related expected future net cash flow (undiscounted and without interest charges) is less than the carrying amount of the asset.

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

Buildings

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

Advances for Future Drilling Contracts

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

Retirement Plans

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

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

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

(Continued)

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

Revenue Recognition

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

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

Income Taxes

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

Derivatives

Gains and losses related to qualifying hedges of firm commitments or anticipated transactions through the use of natural gas futures and option contracts are deferred and recognized in income or as adjustments of carrying amounts when the underlying hedged transaction occurs. In order for futures contracts to qualify as a hedge, there must be sufficient correlation to the underlying hedged transaction. The change in the fair value of derivative instruments which do not qualify for hedging are recognized into income currently.

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. See note 5 to the financial statements.

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.

(Continued)

Reclassifications

Certain items and amounts reported in the 1998 and 1997 consolidated finnancial statements have been reclassified to conform to the current year's reporting format.

Fair Value of Financial Instruments

The carrying values and fair values of the Company 's receivables, payables and debt obligations are estimated to be substantially the same as of December 31, 1999, 1998 and 1997.

New Accounting Standards

Statement of Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), was issued by the Financial Accounting Standards Board in June, 1998. SFAS No. 133 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. SFAS No. 133 is effective for years beginning after June 15, 2000; however, early adoption is permitted. On adoption, the provisions of SFAS No. 133 must be applied prospectively. At the present time, the Company cannot determine the impact that SFAS No. 133 will have on its financial statements upon adoption, as such impact will be based on the extent of derivative instruments, such as natural gas futures and option contracts, outstanding at the date of adoption.

(2) Notes and Accounts Receivable

Included in other assets are noncurrent notes and accounts receivable as of December 31, 1999 and 1998, in the amounts of $494,000 and $617,900 net of the allowance for doubtful accounts of $216,900 and $129,800, respectively.

The allowance for doubtful current accounts receiva ble as of December 31, 1999 and 1998 was $221,500 and $144,800, respectively.

(3) Long-Term Debt

On June 22, 1999 the Company executed an Amendment to its Credit Agreement with First National Bank of Chicago. The amendment provides a $20.0 million borrowing base, subject to adequate oil and gas reserves. The Company has activated $10.0 million of such borrowing base, and has at its discretion the ability to activate the additional $10.0 million. 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 December 31, 2002.

As of December 31, 1999 the outstanding balance was $9,300,000 of which $6,300,000 is at a prime rate of 8.5% and $3,000,000 at a LIBOR rate of 7.73%. At December 31, 1998 there was no balance outstanding. Any amounts outstanding under the credit agreement 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.

(Continued)

(4) Income Taxes

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

	1999	1998	1997
Current:			
Federal	$1,434,300	1,197,800	1,349,600
State	733,000	525,300	638,100
Total current income taxes	2,167,300	1,723,100	1,987,700
Deferred:			
Federal	(65,300)	(500)	(32,100)
State	174,200	244,500	139,800
Total deferred income taxes	108,900	244,000	107,700
Total taxes	$2,276,200	1,967,100	2,095,400

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

	1999 Amount	1998 Amount	1997 Amount
Computed "expected" tax	$3,434,200	2,932,500	3,291,900
State income tax	598,800	508,100	513,400
Percentage depletion	(612,000)	(343,400)	(263,500)
Nonconventional source fuel credit	(846,800)	(696,700)	(846,400)
Adjustments to valuation allowance	(375,000)	(473,200)	(565,200)
Other	77,000	39,800	(34,800)
	$2,276,200	1,967,100	2,095,400

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 1999 and 1998 are presented below:

	1999	1998
Deferred tax assets:		
Allowance for doubtful accounts	$ 175,400	108,600
Drilling notes	105,700	109,200
Alternative minimum tax credit carryforwards (Section 29)	1,982,300	1,783,000
Future abandonment	273,100	-
Deferred compensation	1,213,800	968,500
Other	51,600	148,300
Total gross deferred tax assets	3,801,900	3,117,600
Less valuation allowance	-	(375,000)
Deferred tax assets	3,801,900	2,742,600
Less current deferred tax assets (included in prepaid expenses)	(1,007,600)	(927,400)
Net non-current deferred tax assets	2,794,300	1,815,200
Deferred tax liabilities:		
Plant and equipment, principally due to differences in depreciation and amortization	(6,928,400)	(5,760,200)
Total gross deferred tax liabilities	(6,928,400)	(5,760,200)
Net deferred tax liability	$(4,134,100)	(3,945,000)

(Continued)

The net changes in the total valuation allowance were decreases of $375,000, $473,200 and $782,300 for the years ended December 31, 1999, 1998 and 1997, respectively.

At December 31, 1999, the Company has alternative minimum tax credit carryforwards (Section 29) of approximately $1,982,300 which are available to reduce future federal regular income taxes over an indefinite period.

(5) Common Stock

Options

Options amounting to 145,000, 20,000 and 500,000 shares were granted during 1999, 1998 and 1997, respectively, to certain employees and directors under the Company's Stock Option Plans. These options were granted with an exercise price equal to market value as of the date of grant and vest over a six month period for the 1999 grant and a two year period for the 1998 and 1997 grants. The outstanding options expire from 2000 to 2009.

The estimated fair value of the options granted during 1999, 1998 and 1997 was $2.44, $3.92 and $3.30 per option, respectively. The fair value was estimated using the Black-Scholes option pricing model with the following assumptions for the 1999, 1998 and 1997 grant, respectively : risk-free interest rate of 5.1%, 5.9% and 6.3%, expected dividend yield of 0%, expected volatility of 61.3%, 58.0% and 57.4% and expected life of 7 years.

	Number of Shares	Average Exercise Price	Range of Exercise Prices
Outstanding December 31, 1996	1,582,650	$0.94	.50 - 1.625
Granted	500,000	$5.13	5.13 - 5.13
Exercised	(210,000)	$0.58	.50 - 1.13
Expired	-	$ -	. - .
Outstanding December 31, 1997	1,872,650	$2.10	.94 - 5.13
Granted	20,000	$6.13	6.13 - 6.13
Exercised	(324,333)	$0.94	.94 - .94
Expired	-	$ -	. - .
Outstanding December 31, 1998	1,568,317	$2.39	.94 - 6.13
Granted	145,000	$3.75	3.75 - 3.75
Exercised	(324,333)	$0.94	.94 - .94
Expired	-	$ -	-
Outstanding December 31, 1999	1,388,984	$2.87	.94 - 6.13

As of December 31, 1999, there were 723,984 options outstanding and exercisable in the $.94 to $1.62 exercise price range which have a weighted average remaining contractual life of 2.7 years and weighted average exercise price of $1.05. Also as of December 31, 1999 there were 665,000 options outstanding and exercisable at a $3.75 to $6.13 exercise price range having a weighted average remaining contractual life of 7.9 years and weighted average exercise price of $4.86.

(Continued)

The Company accounts for its stock-based compensation plans under APB 25. 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:

	1999		1998	
	As Reported	Pro Forma	As Reported	Pro Forma
Net income	$7,824,300	$7,336,200	$6,658,000	$5,918,800
Basic earnings per share	$ .50	$ .47	$ .43	$ .38
Diluted earnings per share	$ .48	$ .45	$ .41	$ .37

Stock Redemption Agreement

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

Stock Offerings

In September 1997, the Company completed a private offering of Common Stock pursuant to which it issued and sold 500,000 shares at a price of $4.00 per share and issued warrants for 125,000 shares of Common Stock exercisable during a two-year period ending September 15, 1999 at an exercise price of $6.00 per share, resulting in proceeds to the Company of $2.0 million. The warrants were not exercised and expired on September 15, 1999. No registration rights were granted in connection with the securities issued in this offering.

In November 1997, the Company completed a public offering of 4,077,500 shares of its Common Stock at a price of $6.25 per share. Net proceeds to the Company of approximately $23 million from the sale of common stock was designated to fund development drilling on new and existing properties, potential acquisition of producing properties and general corporate purposes, including working capital and possible acquisitions of complementary businesses.

(Continued)

(6) Employee Benefit Plans

The Company made 401-K Plan contributions of $ 217,400, $202,600 and $171,300 for 1999, 1998 and 1997, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $47,000, $17,000 and $15,500, to the plan in cash during 1999, 1998 and 1997, respectively.

During 1999, 1998 and 1997 the Company expensed and established a liability for $90,000 each year under a deferred compensation arrangement with the executive officers of the Company.

In 1995, a total of 90,000 restricted shares of the Company's common stock were granted to certain employees and available to them upon retirement. The market value of shares awarded was $101,300. This amount was recorded as unamortized stock award. The unamortized stock award is being amortized to expense over the employees' expected years to retirement and amounted to $12,200, $12,200 and $12,300 in 1999, 1998 and 1997, respectively.

At December 31, 1999 and 1998, the Company has recorded as other assets $300,000 and $240,000, respectively as its share of the cash surrender value of the life insurance pledged as collateral for the payment of premiums on split-dollar life insurance policies owned by certain executive officers.

(7) Earnings Per Share

Basic earnings per share is based on the weighted average number of common share outstanding of 15,734,063 for 1999, 15,505,680 for 1998, and 11,278,800 for 1997.

Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding of 16,286,852 for 1999, 16,338,298 for 1998 and 12,540,165 for 1997. Stock options are considered to be common stock equivalents and, to the extent appropriate, have been added to the weighted average common shares outstanding.

(8) Transactions with Affiliates

As part of its duties as well operator, the Company received $24,002,500 in 1999, $22,997,300 in 1998 and $22,985,400 in 1997 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. 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 $10,322,500 in 1999, $9,621,700 in 1998 and $8,113,000 in 1997 for those services.

During 1999, 1998 and 1997, the Company paid $31,600, $30,000 and $63,800, respectively to the Corporate Secretary's law firm for various legal services.

(Continued)

(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. No customer accounted for more than 10.0% of total revenues in 1999 or 1998. One customer, Hope Gas, Inc., a regulated public utility accounted for 12.0% of total revenue in 1997.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may tender their partnership units for repurchase at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are tendered, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if tendered by the investors, is currently approximately $759,000. The Company has adequate capital to meet this obligation.

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

(10) Supplemental Disclosure of Cash Flows

The Company paid $124,200, $0, and $380,000 for interest in 1999, 1998 and 1997, respectively. The Company paid income taxes in 1999, 1998 and 1997 in the amounts of $1,327,800, $2,349,100 and $1,932,500, respectively.

(11) Acquisitions

On February 19, 1998, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1993. The Company purchased approximately $2.3 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1998. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On June 12, 1998 the Company purchased for $3.1 million a majority interest in the assets of Pemco Gas, Inc., a Pennsylvania producing company. The assets include 122 natural gas wells, 2,700 undeveloped acres, gathering systems, natural gas compressors and other facilities. The Company estimates that its interest includes 4.7 Bcf of natural gas reserves. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On November 16, 1998, the Company purchased all of the worki ng interest in a 13 well Antrim Shale production unit and adjacent development locations in Montmorency County, Michigan. The Company estimates that the purchase includes approximately 4 Bcf of proved developed producing reserves and 1.5 Bcf of proved undeveloped reserves, with an acquisition cost of approximately $2.8 million. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On January 29, 1999, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1996. The Company purchased approximately $1.8 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1999. The Company utilized capital received from its Public Stock Offering to fund this purchase.

(Continued)

On December 15, 1999, the Company purchased all of the working interest in 53 producing wells in the D-J Basin of Colorado. The Company estimates that the purchase includes proved developed reserves of approximately 3.6 Bcf of natural gas and 370,000 barrels of oil or approximately 5.8 Bcf equivalent (Bcfe), along with another 3.0 Bcfe of proved undeveloped reserves. Also included in the acquistion was 16.5 net development drilling locations . The total acquisition cost for the wells and locations was $5.2 million. The company utiltized part of its existing line of credit to fund the transaction. The effective date of the transaction was December 1, 1999.

(12) Derivatives and Hedging Activities

The company utilizes commodity based derivative instruments as hedges to manage a portion of its exposure to price volatility stemming from its integrated natural gas production and marketing activities. These instruments consist of natural gas futures and option contracts traded on the New York Mercantile Exchange. The futures and option contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a 12 month period. The Company does not hold or issue derivatives for trading or speculative purposes.

As of December 31, 1999 and 1998, the Company had futures contracts for the purchase of $4,318,000 and $1,120,300 of natural gas, respectively. While these contracts have nominal carrying value, their fair value, represented by the estimated amount that would be received upon termination of the contracts, based on market quotes, was a net value of $350,500 at December 31, 1999 and $(105,400) at December 31, 1998.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 1999 and 1998, cash in the amount of $614,300 and $156,200 was on deposit.

(13) 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,		
	1999	1998	1997
Property acquisition cost:			
Proved undeveloped properties	$2,532,200	1,903,200	3,109,000
Producing properties	6,997,500	8,679,000	85,100
Development costs	17,168,000	14,902,500	9,863,200
	$26,697,700	25,484,700	13,057,300

(Continued)

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.

(14) 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,	
	1999	1998
Proved properties:		
Tangible well equipment	$ 62,996,900	46,722,500
Intangible drilling costs	36,270,300	28,379,200
Well equipment leased to others	4,063,600	4,063,600
Undeveloped properties	2,507,100	2,427,400
	105,837,900	81,592,700
Less accumulated depreciation, depletion and amortization	23,652,000	20,395,400
	$ 82,185,900	61,197,300

(15) 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,		
	1999	1998	1997
Revenue:			
Oil and gas sales	$8,628,400	6,121,700	5,363,600
Expenses:			
Production costs	2,422,000	1,516,700	1,206,000
Depreciation, depletion and amortization	3,220,900	2,392,000	1,629,900
	5,642,900	3,908,700	2,835,900
Results of operations for oil and gas producing activities before provision for income taxes	2,985,500	2,213,000	2,527,700
Provision for income taxes	469,400	398,600	567,800
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$2,516,100	1,814,400	1,959,900

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

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

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

(Continued)

(16) 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, 1999, 1998 and 1997. 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)		
	1999	1998	1997
Proved developed and undeveloped reserves:			
Beginning of year	29,000	45,000	81,000
Revisions of previous estimates	67,000	(10,000)	(27,000)
Beginning of year as revised	96,000	35,000	54,000
New discoveries and extensions	404,000	-	-
Dispositions	-	-	-
Acquisitions	662,000	2,000	-
Production	(8,000)	(8,000)	(9,000)
End of year	1,154,000	29,000	45,000
Proved developed reserves:			
Beginning of year	29,000	45,000	81,000
End of year	798,000	29,000	45,000

	Gas (MCF)		
	1999	1998	1997
Proved developed and undeveloped reserves:			
Beginning of year	80,819,000	57,243,000	43,312,000
Revisions of previous estimates	(4,475,000)	(3,517,000)	875,000
Beginning of year as revised	76,344,000	53,726,000	44,187,000
New discoveries and extensions	24,781,000	23,552,000	2,489,000
Dispositions to partnerships	(8,774,000)	(6,009,000)	-
Acquisitions, net of sales to partnerships in 1997	12,345,000	12,003,000	12,377,000
Production	(3,451,000)	(2,453,000)	(1,810,000)
End of year	101,245,000	80,819,000	57,243,000
Proved developed reserves:			
Beginning of year	64,562,000	42,411,000	35,516,000
End of year	82,628,000	64,562,000	42,411,000

(17) 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.

(Continued)

	Years Ended December 31,		
	1999	1998	1997
Future estimated cash flows	$307,816,000	186,598,000	159,618,000
Future estimated production and development costs	(129,557,000)	(95,670,000)	(69,265,000)
Future estimated income tax expense	(39,930,000)	(20,322,000)	(20,781,000)
Future net cash flows	138,329,000	70,606,000	69,572,000
10% annual discount for estimated timing of cash flows	(79,875,000)	(40,412,000)	(41,636,000)
Standardized measure of discounted future estimated net cash flows	$ 58,454,000	30,194,000	27,936,000

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

	Years Ended December 31,		
	1999	1998	1997
Sales of oil and gas production, net of production costs	$(6,206,000)	(4,605,000)	(4,158,000)
Net changes in prices and production costs	29,547,000	(23,083,000)	(63,573,000)
Extensions, discoveries and improved recovery, less related cost	39,653,000	18,615,000	3,705,000
Dispositions to partnerships	(6,152,000)	(5,762,000)	-
Acquisitions, net of sales to partnerships in 1997	31,915,000	13,938,000	13,299,000
Development costs incurred during the period	17,168,000	14,903,000	9,863,000
Revisions of previous quantity estimates	(4,944,000)	(5,605,000)	2,332,000
Changes in estimated income taxes	(19,608,000)	459,000	12,718,000
Changes in discount	(39,463,000)	1,224,000	24,597,000
Changes in production rates (timing) and other	(13,650,000)	(7,826,000)	(5,109,000)
	$ 28,260,000	2,258,000	(6,326,000)

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)

(18) Business Segments (Thousands)

PDC's operating activities can be divided into three major segments : drilling and developement, natural gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also engages in oil and gas sales to residential, commercial and industrial end-users. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31, 1999, 1998 and 1997 is as follows:

	1999	1998	1997
REVENUES			
Drilling and Development	$42,116	40,447	34,406
Natural Gas Sales	46,988	35,560	33,390
Well Operations	5,314	4,581	4,509
Unallocated amounts (1)	2,392	2,385	1,573
Total	$96,810	82,973	73,878

(1) Includes interest on investments, partnership management fees and gain on sale of assets in 1999 which are not allocated in assessing segment performance.

	1999	1998	1997
SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and Development	$6,608	5,400	6,372
Natural Gas Sales	2,967	2,064	2,780
Well Operations	1,219	1,372	1,701
Unallocated amounts (2)			
General and Administrative expenses	(2,801)	(2,491)	(2,660)
Interest expense	(182)	-	(316)
Other (1)	2,289	2,280	1,805
Total	$10,100	8,625	9,682

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

	1999	1998	1997
SEGMENT ASSETS			
Drilling and Development	$23,957	27,288	22,110
Natural Gas Sales	93,073	65,256	45,888
Well Operations	7,977	7,136	5,953
Unallocated amounts			
Cash	1,967	7,814	20,942
Other	4,934	3,806	3,519
Total	$131,908	111,300	98,412

	1999	1998	1997
EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS			
Drilling and Development	$ 1,710	1,953	2,862
Natural Gas Sales	24,613	23,645	10,207
Well Operations	1,328	947	505
Unallocated amounts	107	85	101
Total	$27,758	26,630	13,675

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(19) Quarterly Financial Data (Unaudited)

Summarized quarterly financial data for the years ended December 31, 1999 and 1998, are as follows:

	1999				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$27,666,300	$21,064,000	$23,841,700	$24,238,600	$96,810,600
Cost of operations	23,837,400	18,411,200	20,038,900	21,439,200	83,726,700
Gross profit	3,828,900	2,652,800	3,802,800	2,799,400	13,083,900
General and administrative expenses	464,400	595,800	859,200	881,600	2,801,000
Interest expense	-	-	88,100	94,300	182,400
	464,400	595,800	947,300	975,900	2,983,400
Income before income taxes	3,364,500	2,057,000	2,855,500	1,823,500	10,100,500
Income taxes	753,700	460,700	842,000	219,800	2,276,200
Net income	$2,610,800	$ 1,596,300	$ 2,013,500	$ 1,603,700	$ 7,824,300
Basic earnings per share	$ .17	$ .10	$ .13	$ .10	$ .50
Diluted earnings per share	$ .16	$ .10	$ .12	$ .10	$ .48

	1998				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$25,247,400	$19,161,600	$16,649,400	$21,915,200	$82,973,600
Cost of operations	21,203,300	16,328,500	15,157,200	19,169,000	71,858,000
Gross profit	4,044,100	2,833,100	1,492,200	2,746,200	11,115,600
General and administrative expenses	440,100	611,000	731,600	707,800	2,490,500
Interest expense	-	-	-	-	-
	440,100	611,000	731,600	707,800	2,490,500
Income before income taxes	3,604,000	2,222,100	760,600	2,038,400	8,625,100
Income taxes	807,300	497,700	180,400	481,700	1,967,100
Net income	$2,796,700	$ 1,724,400	$ 580,200	$1,556,700	$ 6,658,000
Basic earnings per share	$ .18	$ .11	$ .04	$ .10	$ .43
Diluted earnings per share	$ .17	$ .11	$ .03	$ .10	$ .41

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

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years Ended December 31, 1999, 1998 and 1997

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				
1999	$274,600	$272,500	$108,700	$438,400
1998	$275,400	$ 46,800	$ 47,600	$274,600
1997	$287,800	$ 4,200	$ 16,600	$275,400