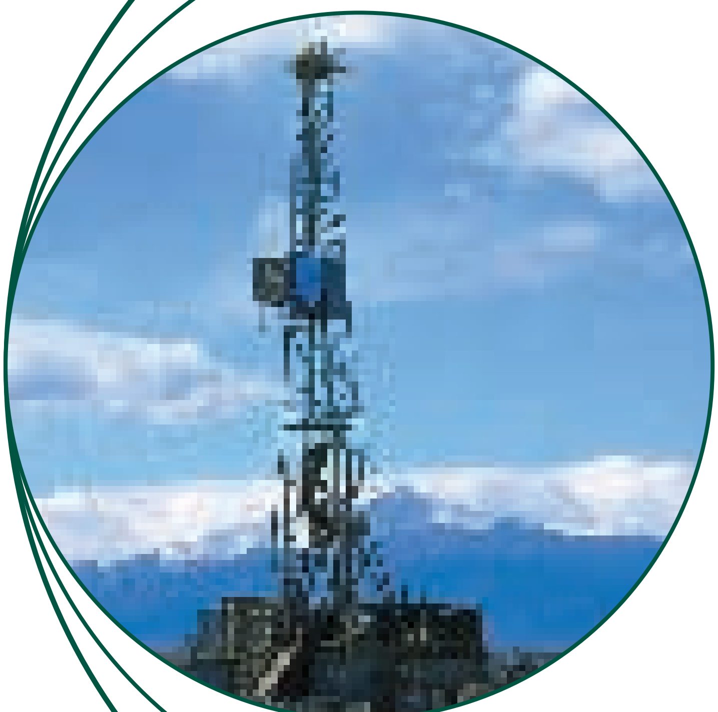
During the first quarter of 2005 the Company determined that there were errors in financial statements that required restatement. As a result the financial statements in the Annual Reports to Shareholders for 2004 and prior period should not be relied upon. The Annual Reports to Shareholders are provided here for narrative and other non-financial information that might be of interest to potential investors. For information on the errors and the restated financial statements see the Company’s 2005 Form 10-K filed on May 31, 2006.



Petroleum Development Corporation

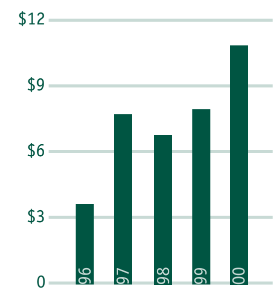
Annual Report 2000

PROFILE

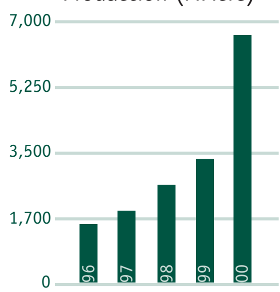
Petroleum Development Corporation (NASDAQ: PETD) (PDC) is a rapidly growing independent oil and gas producer based in Bridgeport, W. Va. The Company's drilling and production operations are in the Appalachian Basin, Michigan, and the Rocky Mountains. While predominantly a natural gas producer, PDC recently added to its oil production through drilling and acquisitions in Michigan and Colorado. PDC also owns and operates a West Virginia-based natural gas marketing company.

Sustained profitable growth is PDC's driving principle. Few peers can match the Company's record of increasing shareholder value over the past decade. PDC expects to continue this record in 2001 and beyond through acquisitions and drilling, and by continuing to expand its technical, geological and operational expertise to generate new opportunities.

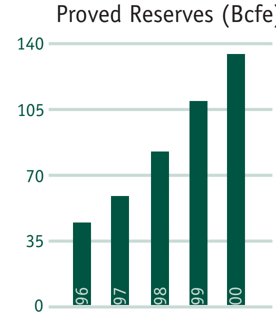
Net Income ($ millions)



Production (MMcfe)



Proved Reserves (Bcfe)



Our 2001 capital budget of $25 million net allows PETD to continue as one of the most active drillers for a company its size. We've drilled 656 gross wells since 1996.

HIGHLIGHTS FOR 2000

- An 11th straight profitable year with record profits in 2000.
- Drilled 97 successful new wells with no dry holes.
- Record production of 6,391 MMcfe, up 83 percent from 1999's 3,499 MMcfe.
- Record drilling partnership sales of $55.6 million.
- Record net income of $10.7 million, a 37 percent increase from 1999.

In separate transactions:

  - Acquired a two-year option from Chevron to lease 53,000 acres in the Piceance Basin with the right to drill up to 10 wells during the initial term.
  - Acquired the right to drill up to 30 wells in the Piceance Basin on leases held by Tom Brown, Inc. of Denver.

- Increased reserves to 132 Bcfe, up 22 percent from 1999's record 108 Bcfe.
- One of only three oil and gas companies recognized by *Forbes Magazine* as one of America's 200 Best Small Companies.

DEAR SHAREHOLDERS

We had a very good year in 2000, both operationally and financially. We achieved and exceeded our financial and operating growth objectives on both corporate and shareholder levels. Our 2000 results benefited by rising oil and gas production, up 83 percent from 1999 to 6.4 Bcfe. About one-third of the increase is attributable to acquisitions of producing wells in Colorado made in December 1999 and April 2000. The remaining two-thirds in production growth stems from new wells we drilled, primarily in Michigan and Colorado.

Drilling revenue from our Company-managed partnerships was up about 2.6 percent in 2000, but with increasing oil and gas prices, interest in the program surged as the year progressed. We raised a record $55.6 million during 2000 from partnership sales, and enjoyed a $43.8 million backlog at the beginning of 2001 for first and second quarter drilling and completion activities. As these funds are converted to drilling revenue in the first and second quarter, they should help us get a great start on what we believe will be another record-setting year in benchmark financial and operating categories.

Along with industry analysts, we firmly believe natural gas prices will be strong through 2001 and beyond. During 2000, PDC used financial hedges to fix prices on a large percentage of our gas production. With the May 2000 price increase, the hedges reduced potential revenues and profits from our oil and gas sales. Conversely, we began 2001 with a large part of our year's production unhedged, and the hedged production is receiving more favorable prices. Hedging is a prudent strategy used by nearly every exploration and production company to lock in predictable cash flow. Higher prices combined with higher production levels, which we estimate to be a 40 percent increase for 2001 production, will have a substantive impact on our 2001 oil and gas sales.

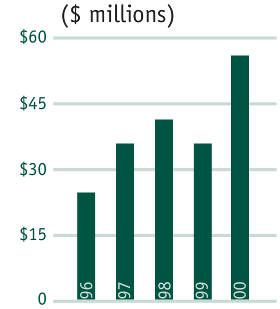
We were recognized for our achievements by the financial community and business publications during 2000. *Forbes Magazine*, in its October 30, 2000 issue, recognized PDC as one of the "200 Best Small Companies in America." In Global E&P Trends 2000, Arthur Andersen reported PDC's 1997-1999 production replacement from all sources as 965 percent, first among the 163 companies included for U.S. operations. We also compared very favorably to other companies on two other important industry barometers, reserve replacement costs and proved acquisitions costs.

In the *Herold 33rd Annual Reserve Replacement Cost Analysis*, John S. Herold, Inc. reported PDC's five-year reserve replacement rate at 880 percent compared to an average of 112 percent for the 225 companies included in the study. PDC, referred to by *Oil and Gas Investor* as an "earnings machine", also ranked as number 28 of the 225 companies for profitability, with profits of $4.31 per barrel of oil equivalent (Boe) versus the group's average of $2.86 per Boe.

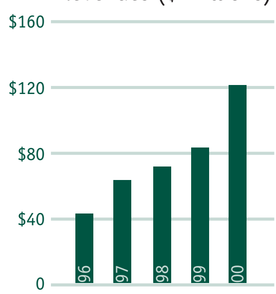
While we appreciate recognition for past success, our focus remains clearly on the future. We are dedicated to sustained profitable growth for our shareholders, in particular by increasing reserves and production. Our 11 consecutive profitable years demonstrate that PDC knows how to earn a profit even when oil and gas prices are down, an anomaly in our competitive industry. We will extend that steak in 2001.

Our Board of Directors approved a 2001 capital budget of $25 million. Of the total, $21.4 million is tentatively designated for development drilling activities, $2.0 million for exploration and new projects, and $1.25 million for acreage leasing. For the exploration and new project component of the budget, we seek prospects with the potential to add significantly to PDC's production and reserves. Here, we assign and are willing to accept a greater degree of risk for our investment than we do for our typical

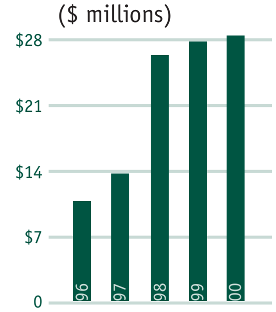
Drilling Partnership Sales ($ millions)



Revenues ($ millions)



Capital Expenditures ($ millions)



Growth through the drill bit accompanies key acquisitions as our plan for enhanced shareholder value.

development-drilling projects. We expect to fund the capital budget entirely from cash flow. Bank debt may be used to fund a portion of possible acquisitions should they present an opportunity to profitably grow reserves and production.

Our investment in PDC-sponsored drilling partnerships represents about half of 2001's development-drilling budget. The balance includes investment as a working interest owner in wells with the partnerships, and investment in non-partnership wells in new areas. While none are presently budgeted, we will continue to seek economically attractive acquisition opportunities that will add to both cash flow and profits. PDC's substantially unused borrowing capacity stands ready to increase our capital budget for the right opportunity.

Because of our robust 1999 and 2000 results in the Rocky Mountain core area, we will focus new drilling activities there, with Michigan as a secondary concentration. The Rocky Mountains offer excellent opportunities for large-scale projects with low finding, development and production costs. Some geologists believe the Rockies hold the largest undeveloped resource potential of any onshore U.S. region. We expect the region to be the centerpiece of our growth plans over the next three to five years.

Ushering in a new U.S. president who has indicated that a national energy policy is an important part of his agenda should benefit PDC and others in our industry. Further, the Rockies region is being discussed as a possible area where additional BLM land, known to have hydrocarbons, could be opened up for exploration in the coming years. A 1999 National Petroleum Council report estimated that 10 percent of U.S. natural gas reserves are in the Rockies, though 40 percent of these reserves are restricted from drilling. By sensibly opening up restricted areas and through higher energy prices, domestic E&P spending should be stimulated. All of the above factors could benefit PDC going forward.

We would like to sincerely recognize and thank the many loyal brokers from over 100 unaffiliated NASD broker-dealer firms who present our popular drilling program to investors throughout the country. They are integral to the program's success and were instrumental in helping PDC post its most successful year ever for partnership sales.

Finally, we warmly welcome Don Nestor to PDC's Board of Directors. Don brings significant knowledge of the Appalachian Basin oil and gas industry and is widely respected in industry and in the accounting profession. His input and hands-on approach will be a valuable addition to the Board as we guide PDC through unprecedented growth.

In the coming year, we will sharpen our focus on substantially growing the company, and with it shareholder value. PDC's exceptional people, access to internally generated prospects, and management's commitment to sustained, profitable growth are a potent, results-driven combination. Our team is among the most loyal and dedicated in the industry. Because of their outstanding efforts, PDC's past is a respected legacy that allows us to go forward with firm confidence in our plan and future.

Very Truly Yours,

James N. Ryan, Chairman and CEO

Steven R. Williams, President

Dale G. Rettinger, Executive Vice President

Steven R. Williams, James N. Ryan, Dale G. Rettinger

Roughnecks tripping another drill string in the Rockies. PDC will drill 80 to 105 wells in the Rocky Mountain region for 2001.

FINANCES

PDC's earnings and operating cash flow rose significantly in 2000 through production growth and higher product prices. Increased production stemmed from 97 new wells drilled with 100 percent success, along with our Colorado acquisition of producing wells. A strong balance sheet coupled with excellent 2000 operating results provided the resources for our outstanding production growth. Net earnings in 2000 of $10.7 million, or $0.65 per diluted share, set another new high. Our cash flow totaled $19.5 million in 2000, up 6.3 percent from 1999. Capital expenditures during 2000 totaled $27.9 million, with 71 percent funded from operations, and the balance from long-term borrowing. At year-end, long-term debt was $17.4 and funded debt / equity ratio was 21 percent, low compared to industry average 83 percent - (AOL Investment Research)

in thousands - except per share amounts

INCOME STATEMENT	2000	1999	1998
Revenues			
Oil and Gas Well Drilling Operations	$ 43,195	$ 42,116	$ 40,447
Oil and Gas Sales	90,420	46,988	35,560
Well Operations Income	5,062	5,314	4,581
Other Income	2,540	2,392	2,385
Total Revenues	141,217	96,811	82,974
Total Costs and Expenses	126,943	86,710	74,348
Costs and Expenses (Excluding Interest and Depreciation, Depletion, and Amortization)	118,813	82,679	71,095
Interest Expense	1,186	182	0
Depreciation, Depletion and Amortization	6,944	4,031	3,254
Income Before Extraordinary Items	10,681	7,824	6,658
Extraordinary Item Net of Income Taxes	–	-	-
Reported Net Income	$ 10,681	$ 7,824	$ 6,658
Per Share			
Net Income	$ 0.66	$ 0.50	$ 0.43
Fully Diluted Net Income	0.65	0.48	0.41
Cash Flow	1.18	0.73	0.62
EBITDA	$ 1.36	$ 0.88	$ 0.73
Weighted Average Common Shares Outstanding (Diluted)	16,437	16,287	16,338
BALANCE SHEET			
Total Current Assets	$ 78,753	$ 42,260	$ 44,009
Property and Equipment	141,299	118,349	92,747
Less Accumulated Depreciation, Depletion, and Amortization	35,345	31,207	27,357
Net Property and Equipment	105,954	87,142	65,390
Total Assets	187,685	132,084	111,300
Working Capital	781	(2,504)	1,525
Long-term Debt, Excluding Current Maturities	$ 17,350	$ 9,300	$ –
Total Shareholders' Equity	$ 82,257	$ 70,725	$ 62,747
Long Term Debt to Shareholders' Equity	21.1%	13.1%	0%
Net Income	$ 10,681	$ 7,824	$ 6,658
Deferred Taxes	1,838	109	244
DD&A	6,944	4,031	3,254
Cash Flow	19,463	11,964	10,156
Interest	1,186	182	–
Income Taxes	1,754	2,276	1,967
EBITDA	$ 22,403	$ 14,314	$ 11,879
Production Costs	$ 4,201	$ 2,422	$ 1,517
Gross Margin percentage	90.3%	94.2%	96.2%

We currently estimate that we will be able to fund our entire 2001 capital budget of $25 million from operating cash flow. Our long-term credit facility with Bank One has a borrowing limit of $30 million, however we believe our reserve base would support a larger line. We estimate that our year-end 2000 reserves and production could support $20 million to $30 million additional borrowing above the year-end debt of $17.3 million.

Our active drilling program is certainly a hallmark, but we continue to seek producing property acquisitions which can add immediately to reserves, production and cash flow. The focused search targets our core operating areas, and new areas where our operational experience, geological knowledge and economies of scale combine to increase the probability of success.

1997	1996	1995	1994	1993	1992	1991
$ 34,405	$ 18,698	$ 13,941	$ 15,190	$ 12,073	$ 14,931	$ 11,070
33,390	26,051	4,151	4,361	4,471	4,867	3,567
4,509	3,929	3,751	3,730	3,843	2,936	2,694
1,573	936	504	524	98	433	507
73,878	49,614	22,346	23,806	20,485	23,166	17,839
64,196	44,964	20,514	22,708	18,890	20,552	16,493
61,220	42,274	18,042	20,559	17,116	18,826	14,931
316	380	320	300	55	54	56
2,660	2,310	2,152	1,848	1,717	1,672	1,505
7,587	3,549	1,481	922	1,321	1,748	870
-	-	-	-	269	-	-
$ 7,587	$ 3,549	$ 1,481	$ 922	$ 1,590	$ 1,748	$ 870
$ 0.67	$ 0.34	$ 0.13	$ 0.08	$ 0.14	$ 0.14	$ 0.07
0.61	0.31	0.13	0.08	0.14	0.16	0.08
0.83	0.53	0.32	0.24	0.30	0.31	0.20
$ 1.01	$ 0.64	$ 0.37	$ 0.27	$ 0.32	$ 0.34	$ 0.22
12,540	11,542	11,611	11,990	11,564	12,633	13,470
$ 53,859	$ 28,619	$ 13,157	$ 12,123	$ 13,506	$ 12,092	$ 10,187
67,792	56,962	48,240	44,960	39,829	37,931	35,896
24,223	22,522	21,127	19,204	21,914	22,365	14,819
43,569	34,440	27,113	25,756	17,915	15,566	21,077
98,412	63,604	40,620	38,325	36,413	34,631	32,040
16,483	(2,357)	(1,520)	(1,614)	289	(590)	(997)
$ –	$ 5,320	$ 2,500	$ 3,100	$ 3,167	$ 3,969	$ 3,354
$ 55,766	$ 23,072	$ 19,921	$ 18,380	$ 17,236	$ 15,347	$ 13,264
0%	23.1%	12.5%	16.9%	18.4%	25.9%	25.3%
$ 7,587	$ 3,549	$ 1,481	$ 922	$ 1,590	$ 1,748	$ 870
108	214	113	97	166	508	325
2,660	2,310	2,152	1,848	1,717	1,672	1,505
10,355	6,073	3,746	2,867	3,473	3,928	2,700
316	380	320	300	55	54	56
2,095	1,101	351	177	365	866	476
$ 12,658	$ 7,340	$ 4,304	$ 3,247	$ 3,727	$ 4,340	$ 2,908
$ 1,206	$ 964	$ 596	$ 735	$ 581	$ 501	$ 511
96.5%	94.8%	95.7%	95.2%	95.2%	96.6%	95.4%

WATTENBERG FIELD CHARACTERISTICS

- Infill development drilling
- Production targets from about 6,500′ to 8,500′
- Primary targets are Niobrara, Codell, J-sand, and Dakota
- 300 undeveloped locations
- PDC operates over 250 Wattenberg field wells
- Wells produce gas / oil mixture
- PDC retains 20% to 40% WI in new wells
- Represents 23% of PDC's 2000 production

2000 ACTIVITY

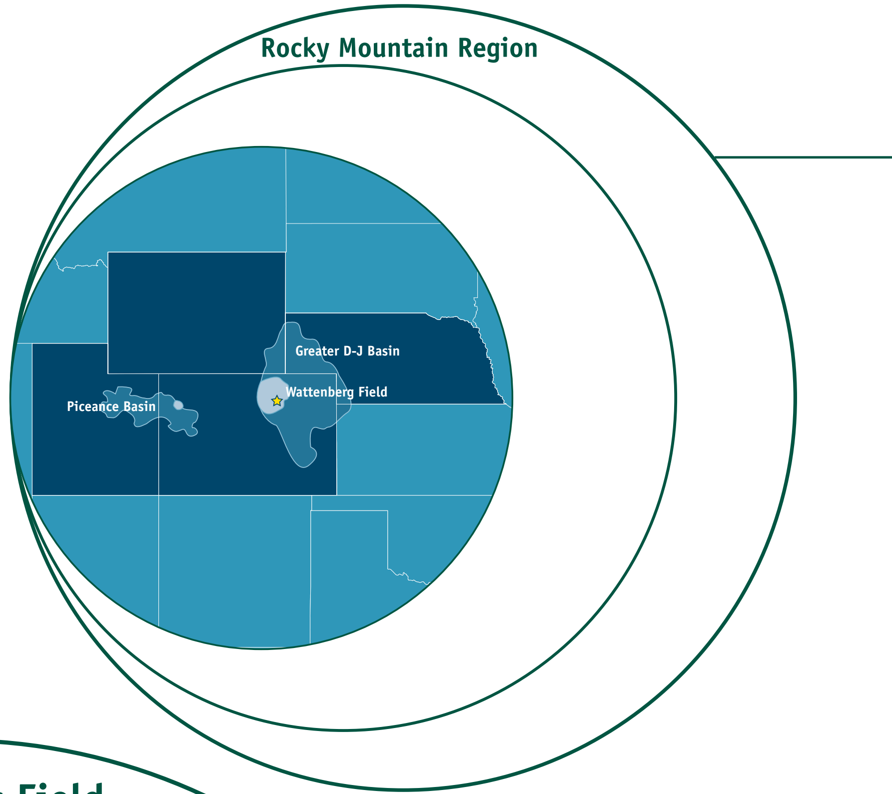
- Purchased 168 producing wells (100% WI)
- Drilled 46 successful new wells with no dry holes
- Obtained drilling rights to more than 200 additional Wattenberg sites

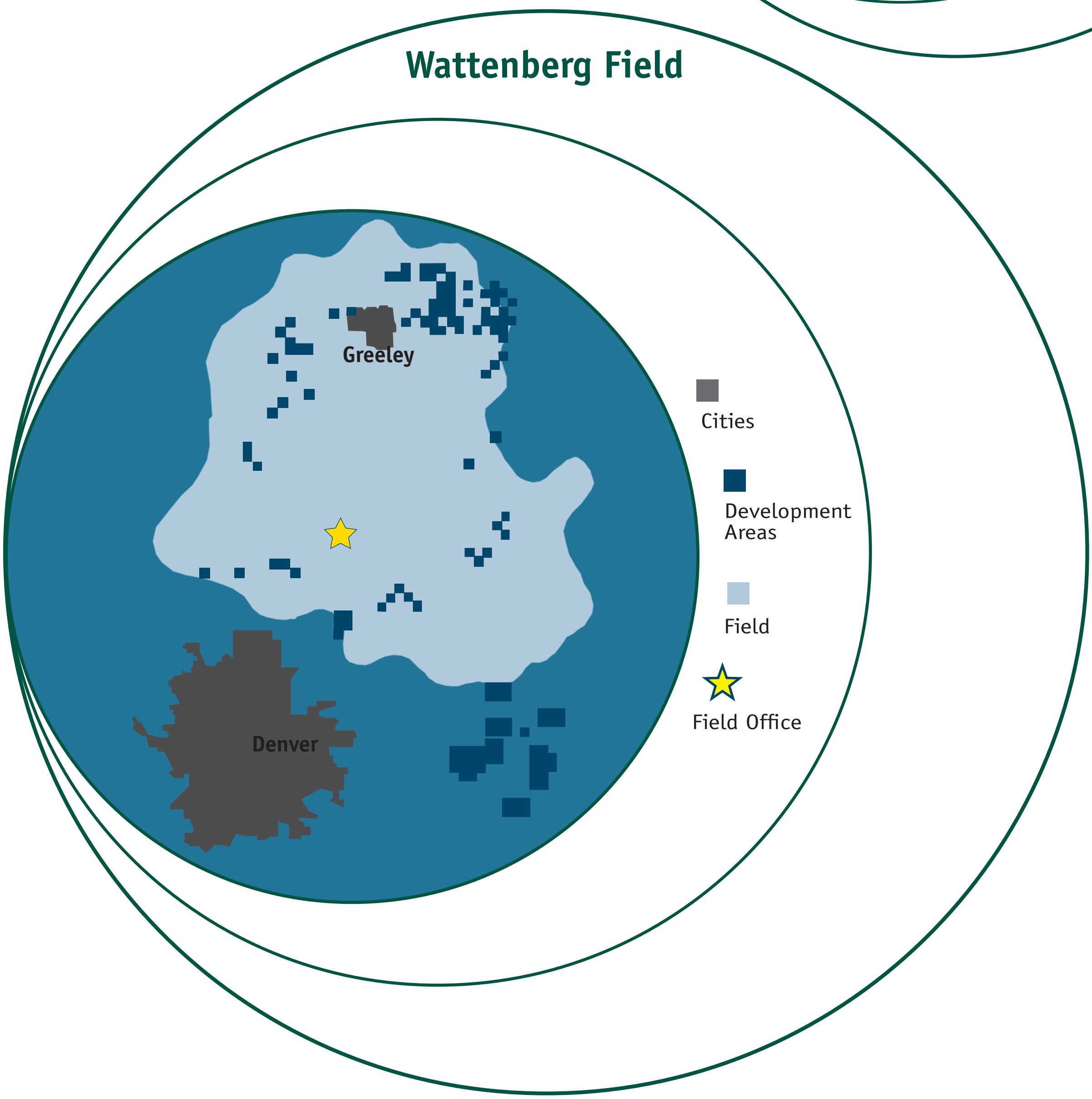
2000 RESERVES

	Gas (MMcf)	Oil (MBbl)
Proved Developed	14,466	1,413
Proved Undeveloped	18,217	399

2001 PLANS

- Drill 50 to 75 new wells
- Seek additional acquisition opportunities and well sites





ROCKY
MOUNTAIN
REGION

ROCKY MOUNTAIN REGION

The Rocky Mountain region is probably the least developed onshore oil and gas province in the U.S. In 1999, PDC added the Rockies as a new core area to capitalize on numerous compelling development opportunities. Inherent similarities, to both Appalachian Basin geology and the drilling and completion practices, allowed us to quickly evaluate and assimilate new opportunities. Our Greeley field office, about 40 miles northeast of Denver, serves as our local base of operations. So far, our Rocky Mountain operations have focused on Wattenberg Field in the Denver-Julesberg Basin and Grand Valley Field in the Piceance Basin. We continue evaluating additional opportunities in the area so we can add to our prospect inventory in the future.

DENVER-JULESBERG BASIN
WATTENBERG FIELD
WELD COUNTY, COLORADO

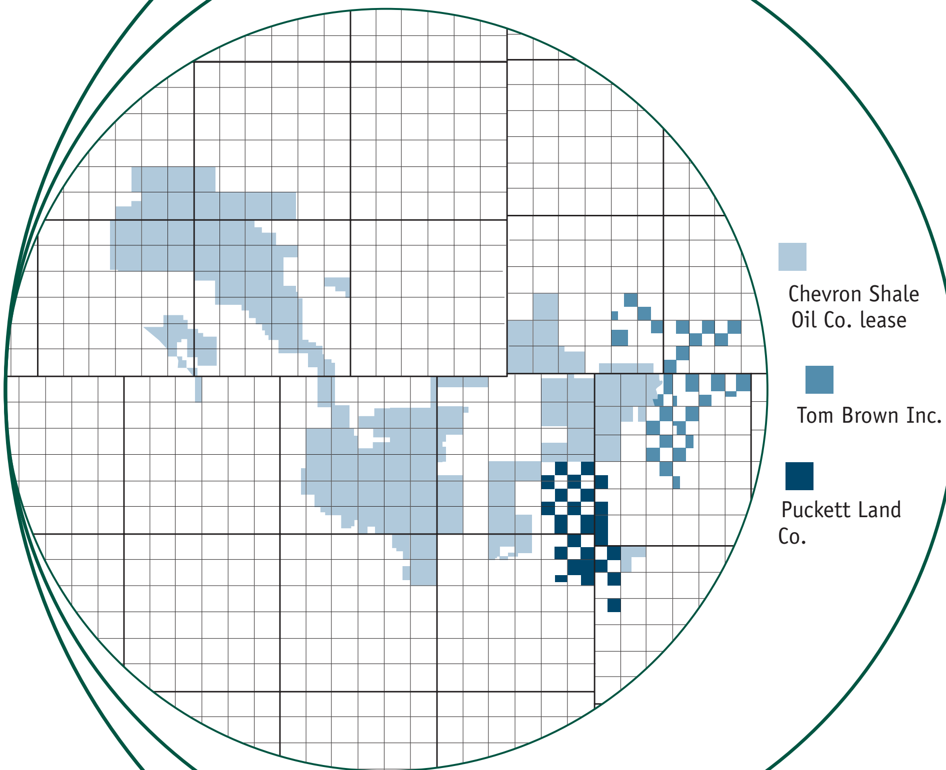
Operations began in Wattenberg field in December 1999 with the acquisition of 53 producing wells. In early April 2000, we added another 168 producing wells in Wattenberg field through an acquisition that included 42 development drilling locations. During the year we obtained access to additional Wattenberg prospects through a series of agreements, bringing our year-end total of available development locations to over 300.

While adding to our prospect inventory, we began an active Wattenberg field development program. During 2000, we drilled 46 new Codell, J–Sand, D–Sand and Dakota wells in the field, all of which were successful. At year-end 2000, 39 of the new wells were in production, with seven awaiting pipeline connections and start-up.

Wattenberg field continues to play a major roll in our future drilling plans. We expect to drill another 50 to 75 wells (10 to 20 net) during 2001. While most new wells will be targeted at the Codell Formation, we will include some J–Sand, D–Sand and Dakota wells.

During 2000, we began a recompletion program on some of our purchased Wattenberg field wells. Area operators continue to find that Codell-Formation reserves and production increase substantially when the Codell is recompleted after a five- to -10 year production period. Our Codell recompletions in 2000 increased average daily production by about 100 Mcfe for each of the 10 recompleted wells. We plan to continue the cost-effective recompletion program in 2001 with at least another 10 first and second quarter recompletions.

Piceance Basin



PICEANCE BASIN CHARACTERISTICS

- Leases and farmouts on over 60,000 acres as of 12/31/2000
- Well depths of about 6,000′ to 10,000′, depending primarily on surface location
- Production from Cambrian, Williams Fork, and Cameo Formations
- 2,000′ producing section includes 150′ to 300′ of net pay in numerous thin sandstone and coal beds
- Initial spacing of 40 acres, with downsizing to 20-acre spacing already approved on portions of leasehold
- Six producing wells drilled by PDC in 2000
- PDC operates and retains 20% to 40% WI

2000 ACTIVITY

- Drilled six successful wells and no dry holes
- Added 53,000 acres to leasehold position

2001 PLANS

- Drill 30 to 40 new wells (20% to 50% WI)

ROCKY
MOUNTAIN
REGION

PICEANCE BASIN
GRAND VALLEY FIELD
GARFIELD COUNTY, COLORADO

In December 1999, PDC signed a lease for the right to develop the 7,500-acre Puckett Lease in Garfield County, Colo., our first step in preparing to drill in the Piceance Basin. During 2000, we added to our lease position through several transactions, including an option to lease up to 53,000 acres from Chevron with a right to drill up to 10 wells before exercising the lease option. We also entered into a farmout agreement with Denver-based Tom Brown, Inc., to drill up to 30 wells on a 4,000-acre block adjacent to both our Puckett Lease and the Chevron acreage. To help finance these transactions, we sold a 50 percent checkerboard on our Puckett lease to a small privately held independent. As a result, we entered 2001 with access to over 60,000 acres in the gas-rich Piceance Basin.

PDC's Piceance Basin drilling operations began in first quarter 2000, and by June, six wells were drilled, completed and placed into production. During the balance of 2000, the six wells averaged 633 Mcf per day, totaling over 825 MMcf of annual gross production.

Our 2001 drilling plans include aggressive development of our Piceance Basin acreage position. We expect to drill 20 to 30 gross (five to 10 net) new wells, including 15 to 18 in the first and second quarters. Our extensive acreage position in the area provides us with numerous, quality drilling opportunities, and strong natural gas prices greatly enhance the overall economics.

Michigan Basin

MICHIGAN BASIN CHARACTERISTICS

- **Fractured shale, dewatered and produced similar to coal bed methane wells**
- **PDC operates 209 wells**
- **Well depths of approximately 1,000′**
- **41,800 gross acres**
- **Represents about 36% of PDC's 2000 production**

2000 ACTIVITY

- **Drilled 28 new wells with no dry holes**
- **Increased production about 40%**

2000 RESERVES

	Gas (MMcf)	Oil (MBbl)
Proved Developed	30,777	54
Proved Undeveloped	8,292	240

2001 PLANS

- **Drill 20 to 30 new wells**
- **Seek additional development acreage**

MICHIGAN
BASIN

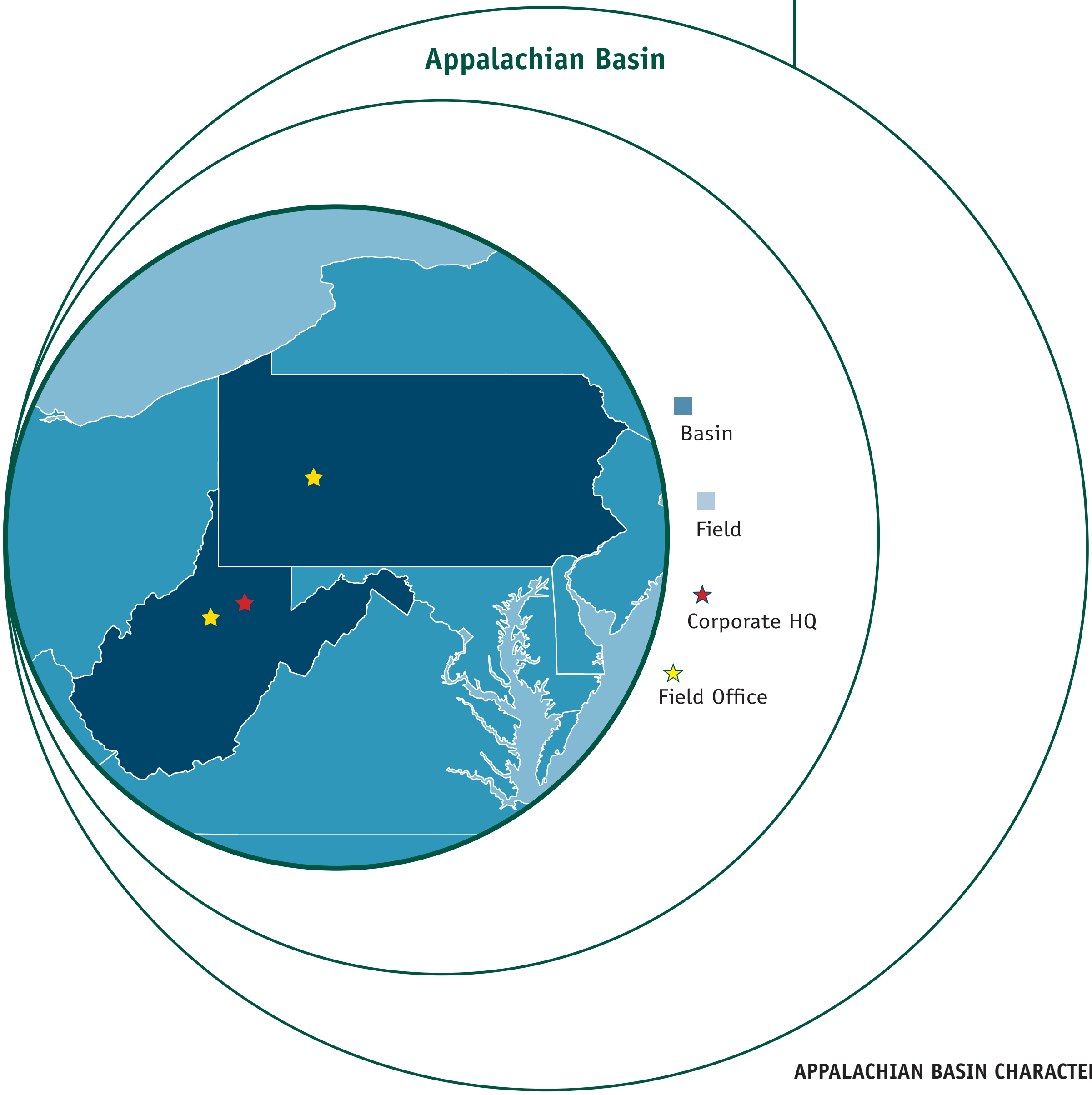
MICHIGAN BASIN
ANTRIM SHALE
MICHIGAN

Petroleum Development began its Michigan drilling operations in 1997 and in 1998, acquired a 13-well producing field here to help bolster a new core area. Six production employees staff the Company's Michigan field office in Ossineke, and geological and engineering activities are managed from our Bridgeport office.

At year-end 2000, PDC had 209 producing wells in Michigan with another two wells drilled but not yet in production. The Company produced 2.3 Bcfe during 2000, with an average daily production rate of 6,350 Mcfe. The 4th quarter 2000 average daily production rate was 7,050 Mcfe, up 42 percent from December 1999's 4,950 Mcfe. Michigan production rates are expected to continue rising as wells already drilled, but not yet in production, are connected for sales and additional new wells are drilled. Production rates on our wells in the Antrim shale typically continue to increase for six to 18 months after start–up as the water initially filling the reservoir is produced and gas finds a more direct path to the wellbore.

During 2000, 28 new wells were drilled in Michigan, all of which were successful. Included in the total are two successful wells drilled to test the Richfield Formation, an oil-producing zone at a depth of 4,300 feet. An offsetting Richfield well drilled in 1999 produced about 9,200 barrels of oil during 2000. We plan to continue developing the field during 2001 as part of our partnership drilling program.

Our primary target for new Michigan wells is the Antrim shale. In productive areas, the Antrim shale is generally located at depths of approximately 1,000 feet. Economic gas reserves are found in areas of fractured shale that is initially water-filled. Dewatering is necessary before gas production can begin from fractured shales. As dewatering continues, production peaks and the wells begin a long, gradual decline. As with Appalachian Basin wells, Michigan wells tend to enjoy long and predictable productive lives exceeding 20 years. We expect to drill another 20 to 30 Antrim shale wells in 2001.



APPALACHIAN BASIN CHARACTERISTICS

- PDC's original operating area
- Over 1,500 wells operated
- Production from long-lived Mississippian and Devonian tight Formations
- 76,500 gross acres
- 39% of 2000 production

2000 ACTIVITY

- Drilled 17 successful wells

2000 RESERVES

	Gas (MMcf)	Oil (MBbl)
Proved Developed	46,888	60

2001 PLANS

- Recompletions and workovers
- Maximize existing production
- Seek new exploratory and development opportunities

APPALACHIAN
BASIN

APPALACHIAN BASIN

PDC's Appalachian Basin properties produced about 39 percent of PDC's 2000 oil and gas. Most West Virginia properties are located in the north–central part of the state in close proximity to our Bridgeport headquarters. A second concentration of Appalachian wells is located in west-central Pennsylvania, with a field office located in Mahaffey, Pa. The preponderance of our Pennsylvania wells have been drilled or acquired since 1990.

At the end of 2000, we operated 1,538 wells in the Appalachian region. PDC's production here was 2.5 Bcfe during 2000, for an average daily rate of 6,900 Mcfe. During 2000, we drilled 17 new wells.

Historically, PDC has concentrated on Devonian- and Mississippian-aged sandstones and fractured Devonian shales. While these targets seldom have high initial production rates, they are widespread and predictable, ultimately resulting in a 92 percent successful completion rate. Productive lives exceeding 25 to 30 years are common, providing an excellent production base that is accurately forecast due to a flat, per-well decline curve.

During 2000, other Appalachian operators drilled a number of successful test wells to the Trenton-Black River Formation. Currently, PDC is reviewing its acreage position for possible Trenton-Black River drilling and completion potential, as well as identifying prospective acreage for key acquisitions.

In the past, Appalachian natural gas production has sold at a premium to gas produced in most other areas because of its proximity to major Northeast national gas markets. Recently, warm winters have reduced the premium substantially. However, the return to more typical winter conditions in 2000-2001 saw a return of a $1.00-plus Appalachian premium in January 2001. If the tight gas market of 2000 continues in 2001, area producers expect to continue to receive a higher Appalachian price relative to other North American natural gas basins.

NATURAL GAS MARKETING

During 2000, PDC had two subsidiaries involved in wholesale and retail purchase and sale of natural gas in the Appalachian region. Riley Natural Gas (RNG) is a natural gas marketing company operating out of our Bridgeport headquarters. In the Appalachian Basin, RNG purchases gas from more than 100 unaffiliated producers and resells the gas to end- users and other marketers. During 2000, RNG marketed $84.7 million of natural gas (20.3 Bcf) for PDC and other producers in the Appalachian Basin. RNG also manages our gas marketing in Michigan and the Rockies.

Another subsidiary, Paramount Natural Gas (PNG) is a regulated gas utility distributing natural gas to residential, commercial and industrial customers in central Ohio. At the end of 2000, we sold the PNG assets to another Ohio gas utility. Although PNG contributed to PDC's growth and profitability over the years, changes in our geographic and operating focus, combined with increased competition, made this divestiture attractive for both financial and operating reasons. The sale price was slightly in excess of PNG's book value. PNG had sales of $2.4 million in 2000.

OPERATING DATA

From an operating perspective, 2000 was undeniably an outstanding year. We drilled 97 new wells without a single dry hole bringing our four-year total in excess of 620 successful new wells, making PDC one of the most active drillers among small independents. Couple the 97 new wells with the 168 producing wells we acquired in Colorado, and we now operate over 2,024 wells in our three operating areas. Our national presence is spread over 240,000 total acres.

ESTIMATED OIL AND GAS RESERVES	2000	1999	1998
Proved Developed Reserves			
Natural Gas (MMcf)	92,131	82,628	64,562
Oil (MBbl)	1,527	798	29
Total (MMcfe)	101,293	87,416	64,736
Total Reserves			
Natural Gas (MMcf)	118,640	101,245	80,819
Oil (MBbl)	2,166	1,154	29
Total (MMcfe)	131,636	108,169	80,993
Percent Proved Developed	77%	81%	80%
SEC PV-10 After Tax (000)	$ 104,639	$ 58,454	$ 30,194
OIL AND GAS OPERATIONS			
Production			
Natural Gas (MMcf)	5,737	3,451	2,453
Oil (MBbl)	109	8	8
Total (MMcfe)	6,391	3,499	2,501
Average Sales Price			
Natural Gas (per MMcf)	$ 2.74	$ 2.46	$ 2.46
Oil (per MBbl)	$ 29.99	$ 18.75	$ 10.61
Natural Gas Equivalents (per Mcfe)	$ 2.98	$ 2.47	$ 2.45
Lease Operating Expenses and Production Taxes (per Mcfe)	$ 0.66	$ 0.69	$ 0.61
EBITDA (per Mcfe)	$ 3.50	$ 4.09	$ 4.75
Operating Margin Percentage (EBITDA / Operating Revenues)	16%	15%	14%
Depreciation, Depletion and Amortization Costs (per Mcfe)	$ 1.09	$ 1.15	$ 1.30
Wells Operated	2,024	1,796	1,601
Net Wells Owned	1,052	869	692
Average Ownership in Operated Wells	52%	48%	43%
DRILLING			
Gross Wells			
Exploratory	–	5	1
Development	97	173	212
Dry Hole	–	13	12
Success Rate	100%	93%	94%
Production Replacement, All Sources (%)	467%	877%	1,039%

Not surprisingly, an unsurpassed year in drilling and acquisitions boosted our oil and gas production to record levels of 6.391 Bcfe, an 83 percent increase over 1999's 3.499 Bcfe. Our newer core areas, Colorado and Michigan, provided most of the production jump. Michigan's production increases resulted from new wells drilled in 1999 and 2000, while Colorado benefited from the December 1999 and April 2000 acquisitions, in addition to new wells we drilled.

1997	1996	1995	1994	1993	1992	1991
42,411	35,516	29,326	27,746	20,181	20,477	18,938
45	81	140	79	91	78	84
42,681	36,002	30,166	28,220	20,727	20,945	19,442
57,243	43,312	33,829	32,225	24,660	24,980	24,432
45	81	140	79	91	78	84
57,243	43,798	34,669	32,699	25,206	25,448	23,936
75%	82%	87%	86%	82%	82%	81%
$ 27,936	$ 34,262	$ 21,060	$ 14,445	$ 14,018	$ 15,515	$ 13,028
1,810	1,495	1,336	1,195	965	948	867
9	7	11	11	10	16	12
1,864	1,537	1,402	1,261	1,025	1,044	939
$ 2.88	$ 3.04	$ 1.75	$ 2.01	$ 2.24	$ 2.41	$ 2.16
$ 16.10	$ 16.35	$ 15.80	$ 14.41	$ 16.62	$ 18.21	$ 17.52
$ 2.87	$ 3.03	$ 1.79	$ 2.03	$ 2.27	$ 2.47	$ 2.22
$ 0.65	$ 0.63	$ 0.58	$ 0.58	$ 0.57	$ 0.48	$ 0.54
$ 6.79	$ 4.78	$ 3.07	$ 2.57	$ 3.64	$ 4.16	$ 3.10
17%	15%	19%	14%	18%	19%	16%
$ 1.43	$ 1.50	$ 1.54	$ 1.47	$ 1.68	$ 1.60	$ 1.60
1,281	1,150	889	829	725	699	707
505	481	309	298	226	224	217
39%	42%	35%	36%	31%	32%	31%
–	–	–	–	3	–	–
168	97	72	75	56	80	53
10	5	8	4	10	7	4
94%	95%	89%	95%	83%	91%	92%
836%	694%	241%	694%	76%	245%	176%

FINANCIAL
CONTENTS

Statements in this annual report that are not historical facts are forward-looking statements made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. In this report forward-looking statements are generally accompanied by words such as "anticipate," "believe," "estimate," "expect," "forecast," "intend," "possible," "potential," "predict," "project," or other similar words that convey the uncertainty of future events or outcomes. Although we believe these forward-looking statements are reasonable, they are based upon a number of assumptions concerning future conditions, any or all of which may ultimately prove to be inaccurate. Forward-looking statements involve a number of risks and uncertainties. Some of the important factors that could cause actual results to differ materially from the forward-looking statements include:

- General economic, financial and business conditions that affect the price of natural gas or crude oil;
- U.S. and worldwide crude oil and natural gas supply and demand;
- Variation in commodity prices of natural gas and crude oil;
- Actions and activities of competitors;
- Changes in statutes and regulations affecting our business;
- Unanticipated costs to comply with new and existing regulations;
- Delays or inability to obtain necessary permits;
- Differences between expected and actual production;
- Risks related to exploration and development drilling outcomes;
- Timely availability of required drilling services and materials;
- Actual compared to estimated reserves;
- Our success in replacing and developing new reserves;
- Actual production and profitability of past and future acquisitions;
- Sales and profitability of our drilling programs;
- Unanticipated changes in the level of operating expenses;
- Hazards common to operating facilities (including equipment malfunction, explosions, fires, oil spills, and the effects of severe weather conditions);
- Changes in the cost and availability of financing;
- Litigation to which we might be a party in the future; and
- Our ability to implement our business strategy.

These factors and others that we have not specifically identified and may not anticipate could cause actual results to differ materially from those expressed in any forward-looking statements we make. All forward-looking statements included in this report are expressly qualified in their entirety by the foregoing cautionary statement. In addition, we undertake no obligation to update any forward-looking statements or the associated cautionary language to reflect changes in our expectations resulting from the new information or future events.

A $100,000 Wattenberg Codell–Formation recompletion increases daily production by an average of 100 Mcfe. The Company will recomplete about 10 to 20 wells here in 2001.

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, 2000 COMPARED WITH DECEMBER 31, 1999

REVENUES

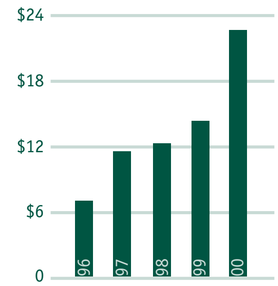
Total revenues for the year ended December 31, 2000 were $141.2 million compared to $96.8 million for the year ended December 31, 1999, an increase of approximately $44.4 million, or 45.9%. Drilling revenues for the year ended December 31, 2000 were $43.2 million compared to $42.1 for the year ended December 31, 1999, an increase of approximately $1.1 million, or 2.6%. Natural gas sales from the marketing activities of RNG for the year ended December 31, 2000 were $71.4 million compared to $38.4 million for the year ended December 31, 1999, an increase of approximately $33.0 million or 85.9%. Such increase was due to increased volumes of gas sold with higher average sales prices. Oil and gas sales from the Company's producing properties for the year ended December 31, 2000 were $19.0 million compared to $8.6 million for the year ended December 31, 1999, an increase of approximately $10.4 million or 120.9%. Such increase was due to increased production which resulted from acquisitions of producing properties along with new wells drilled and higher average sales prices of natural gas and oil from the Company's producing properties. Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas market has remained prevalent in the last few years. From the third quarter of 1998 through the first quarter of 1999, we experienced a decline in energy commodity prices. However, in the summer of 1999 and continuing into early 2000, prices improved. For the months of April through December, 2000, we had certain natural gas hedges in place that prevented us from realizing the full impact of this price environment. Despite this limitation, our realized natural gas price for each month in the year 2000 was higher than the previous year. In the final months of 2000, the NYMEX futures market reported unprecedented natural gas contract prices. During 2000, the hedging activities resulted in oil and gas sales being $5.2 million lower than if the Company had not hedged. Well operations and pipeline income for the year ended December 31, 2000 was $5.1 million compared to $5.3 million for the year ended December 31, 1999, a decrease of approximately

$200,000 or 3.8%. Other income for the year ended December 31, 2000 was $2.5 million compared to $2.4 million for the year ended December 31, 1999, an increase of approximately $100,000 or 4.2%.

COSTS AND EXPENSES

Costs and expenses for the year ended December 31, 2000 were $126.9 million compared to $86.7 million for the year ended December 31, 1999, an increase of approximately $40.2 million, or 46.4%. Oil and gas well drilling operations costs for the year ended December 31, 2000 were $35.2 million compared to $35.5 million for the year ended December 31, 1999, a decrease of approximately $300,000 or 0.8%. The costs of gas marketing activities for the year ended December 31, 2000 were $71.6 million compared to $38.5 million for the year ended December 31, 1999, an increase of $33.1 million or 86.0%. Such increase was due to the increased gas marketing activity of RNG with increased volumes purchased at higher average sale prices. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during 2000. Oil and gas production costs from the Company's producing properties for the year ended December 31, 2000 were $8.3 million compared to $5.7 million for the year ended December 31, 1999 an increase of $2.6 million or 45.6%. Such increase was due to the increased production volumes from the Company's producing properties. General and administrative expenses for the year ended December 31, 2000 were $3.6 million compared to $2.8 million for the year ended December 31, 1999, an increase of approximately $800,000. Depreciation, depletion and amortization costs for the year ended December 31, 2000 were $6.9 million compared to $4.0 million for the year ended December 31, 1999, an increase of approximately $2.9 million or 72.5%. Such increase was due to the increased amount of investment in oil and gas properties owned by the Company. Interest costs for the year ended December 31, 2000 were $1.2 compared to $200,000 for the year ended December 31, 1999 an increase of approximately $1.0 million. The increase was due to the Company utilizing its credit agreement to purchase oil and gas properties.

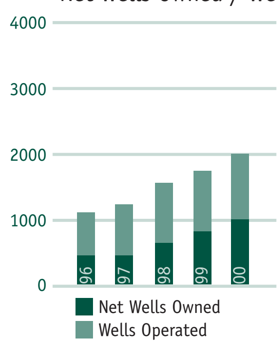
EBITDA ($ millions)



NET INCOME

Net income for the year ended December 31, 2000 was $10.7 million compared to $7.8 million for the year ended December 31, 1999, an increase of approximately $2.9 million or 37.2%.

Net Wells Owned / Wells Operated

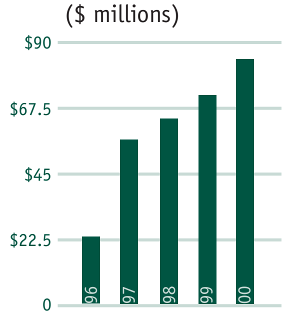


YEAR ENDED DECEMBER 31, 1999 COMPARED WITH DECEMBER 31, 1998

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. Natural gas sales from the marketing activities of RNG for the year ended December 31, 1999 were $38.4 million compared to $29.2 million for the year ended December 31, 1998, an increase of approximately $9.2 million or 31.5% Oil and gas sales from the Company's producing properties for the year ended December 31, 1999 were $8.6 million compared to $6.3 million for the year ended December 31, 1998, an increase of approximately $2.3 million or 36.5%. Such increase was due to increased production of natural gas and oil from the Company's producing properties which resulted from acquisitions of producing properties along with new wells drilled. 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

Total Shareholders' Equity ($ millions)



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%. The cost of gas marketing activities for the year ended December 31, 1999 were $38.5 million compared to $29.3 million for the year ended December 31, 1998, an increase of $9.2 million or 31.4%. Such increase was due to the increased gas marketing activity of RNG. Oil and gas production costs from the Company's producing properties for the year ended December 31, 1999 were $5.7 million compared to $4.2 million for the year ended December 31, 1998, an increase of 1.5 million or 35.7%. Such increase was due to the increased production volumes 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%.

LIQUIDITY AND CAPITAL RESOURCES

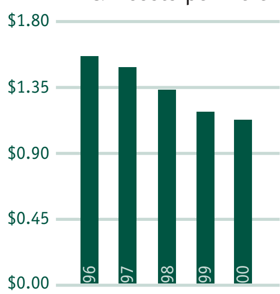
The Company funds its operations through a combination of cash flow from operations, capital raised through stock offerings and drilling partnerships, and use of the Company's credit facility. Operational cash flow is generated by sales of natural gas from the Company's well interests, well drilling 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 volumes 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 Bank One, formerly First National Bank of Chicago, which provides a borrowing base of $30.0 million, subject to adequate oil and natural gas reserves. As of December 31, 2000, the balance outstanding on the line of credit is $17.35 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, 2004.

The Company closed four public drilling partnerships during 2000. The total amount received during 2000 was $55.6 million compared to $36.1 million for 1999. The Company closed its fourth program of 2000 on December 27, 2000 in the amount of $25.0 million and will drill the wells during the first quarter 2001. 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.

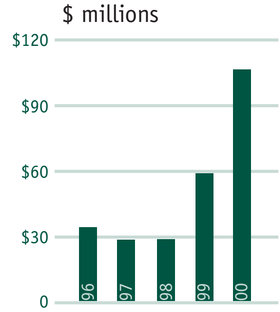
DD&A Costs per Mcfe



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 limited partnership interest in 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 3.0 Bcfe of proved undeveloped reserves attributable to these 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.

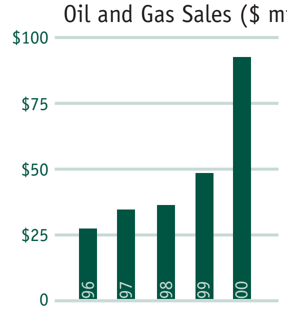
SEC PV–10 (after tax)
$ millions



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

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.

Oil and Gas Sales ($ millions)



NEW ACCOUNTING STANDARDS

Statement of Accounting Standards No. 133 and No. 138, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133/138), was issued by the Financial Accounting Standards Board. SFAS No. 133/138 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. The Company is required to adopt the provisions of SFAS 133/138 effective January 1, 2001. On adoption, the provisions of SFAS No. 133/138 must be applied prospectively. The natural gas futures and options and the interest rate swap agreement discussed in note 12 are derivatives pursuant to SFAS 133/138. The Company's derivatives will be treated as hedges of committed and/or anticipated transactions and have a total estimated fair value of $(20,131,800) on December 31, 2000.

On January 1, 2001, the Company will record this estimated fair value as a liability with a corresponding adjustment to accumulated other comprehensive income (AOCI). The adjustment to AOCI will be recorded net of the related tax effects.

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, 2000 is $46,872,000 with an average interest rate of 5.24 percent. As of December 31, 2000, the Company has long-term debt of $17,350,000 of which $10,000,000 is subject to an interest rate swap at a rate of 8.39%, $5,000,000 at a LIBOR rate of 8.52% and $2,350,000 was subject to a prime rate of 9.50%.

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, 2000, PDC had entered into a series of natural gas future contracts and options contracts. Open future contracts maturing in 2001 are for the sale of 4,923,320 dt of natural gas with a weighted average price of $4.07 dt resulting in a total contract amount of $20,134,300, and a fair market value of $(19,340,400). Open option contracts maturing in 2001 are for the sale of 2,276,400 dt with a weighted average floor price of $3.68 dt and a fair value of $(757,600). As of December 31, 1999, PDC had entered into a series of natural gas future contracts. Open future contracts maturing in 2000 were for the sale of 1,820,000 dt of natural gas with a weighted average price of $2.3725 dt resulting in a total contract amount of $4,317,950, and a fair market value of $350,500. The average NYMEX closing price for natural gas for the years 2000, 1999, and 1998 was $3.88 dt, $2.27 dt and $2.11 dt. The average NYMEX closing price for oil for the years 2000, 1999, and 1998 was $30.95 bbl, $18.06 bbl and $14.64 bbl. Future near-term gas prices will be affected by various supply and demand factors such as weather, government and environmental regulation and new drilling activities within the industry.

DISCLOSURE OF LIMITATIONS

As the information above incorporates only those exposures that exist at December 31, 2000, it does not consider those exposures or positions which could arise after that date. As a result, the Company's ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, the Company's hedging strategies at the time, and interest rates and commodity prices at the time.

INDEPENDENT AUDITORS' REPORT

The Stockholders and Board of Directors
Petroleum Development Corporation:

We have audited the accompanying consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 2000 and 1999, and the related statements of income, stockholders' equity and cash flows for each of the years in the three–year period ended December 31, 2000. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the 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, 2000 and 1999, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

Pittsburgh, Pennsylvania
March 8, 2001

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2000 AND 1999

	2000	1999
ASSETS		
Current assets:		
Cash and cash equivalents	$ 43,933,700	$ 28,444,900
Restricted cash	2,938,300	614,300
Notes and accounts receivable	23,648,000	10,263,200
Inventories	1,097,900	577,600
Prepaid expenses	7,134,800	2,360,100
Total current assets	78,752,700	42,260,100
Properties and equipment:		
Oil and gas properties (successful–efforts accounting method)	131,271,900	105,837,900
Pipelines	6,147,800	8,643,400
Transportation and other equipment	2,704,300	2,686,800
Land and buildings	1,174,600	1,181,000
	141,298,600	118,349,100
Less accumulated depreciation, depletion and amortization	35,344,700	31,207,300
	105,953,900	87,141,800
Other assets	2,977,900	2,681,700
Total Assets	$ 187,684,500	$ 132,083,600

LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 27,742,600	$ 14,678,900
Accrued taxes	-	276,400
Other accrued expenses	3,979,900	2,643,700
Advances for future drilling contracts	43,809,400	25,137,400
Funds held for future distribution	2,440,100	2,027,600
Total current liabilities	77,972,000	44,764,000
Long-term debt	17,350,000	9,300,000
Other liabilities	4,396,800	3,160,600
Deferred income taxes	5,708,800	4,134,100
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 16,244,044 and 15,737,795 shares	162,400	157,400
Additional paid-in capital	32,917,000	32,071,000
Retained earnings	49,177,500	38,496,500
Total stockholders' equity	82,256,900	70,724,900
Total Liabilities and stockholders' equity	$ 187,684,500	$ 132,083,600

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF INCOME
YEARS ENDED DECEMBER 31, 2000, 1999, 1998

	2000	1999	1998
Revenues:			
Oil and gas well drilling operations	$ 43,194,700	$ 42,115,600	$ 40,447,100
Gas sales from marketing activities	71,402,400	38,359,700	29,244,900
Oil and gas sales	19,017,300	8,628,400	6,315,400
Well operations and pipeline income	5,061,600	5,314,500	4,581,000
Other income	2,540,500	2,392,400	2,385,200
	141,216,500	96,810,600	82,973,600
Costs and expenses:			
Cost of oil and gas well drilling operations	35,244,300	35,507,300	35,047,500
Cost of gas marketing activities	71,648,500	38,459,000	29,350,200
Oil and gas production costs	8,303,600	5,729,200	4,206,700
General and administrative expenses	3,616,900	2,801,000	2,490,500
Depreciation, depletion and amortization	6,943,500	4,031,200	3,253,600
Interest	1,186,000	182,400	-
	126,942,800	86,710,100	74,348,500
Income before income taxes	14,273,700	10,100,500	8,625,100
Income taxes	3,592,700	2,276,200	1,967,100
Net income	$ 10,681,000	$ 7,824,300	$ 6,658,000
Basic earnings per common share	$ 0.66	$ 0.50	$ 0.43
Diluted earnings per common and common equivalent share	$ 0.65	$ 0.48	$ 0.41

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2000, 1999, 1998

	Common stock Issued					
	Number of Shares	Amount	Additional paid-in capital	Warrants outstanding	Retained earnings	Total
Balance December 31, 1997	15,245,758	$152,500	31,553,100	46,300	24,014,200	55,766,100
Issuance of common stock:						
Exercise of employee stock options	324,333	3,200	300,800	-	-	304,000
Amortization of stock award	-	-	12,200	-	-	12,200
Repurchase and cancellation of treasury stock	(59,329)	(600)	(303,400)	-	-	(304,000)
Income tax benefit from the exercise of stock options	-	-	310,400	-	-	310,400
Net income	-	-	-	-	6,658,000	6,658,000
Balance December 31, 1998	15,510,762	$ 155,100	31,873,100	46,300	30,672,200	62,746,700
Issuance of common stock:						
Exercise of employee stock options	324,333	3,200	300,800	-	-	304,000
Amortization of stock award	-	-	12,200	-	-	12,200
Repurchase and cancellation of treasury stock	(97,300)	(900)	(303,100)	-	-	(304,000)
Income tax benefit from the exercise of stock options	-	-	141,700	-	-	141,700
Warrants expired	-	-	46,300	(46,300)		-
Net income	-	-	-	-	7,824,300	7,824,300
Balance December 31, 1999	15,737,795	$157,400	32,071,000	-	38,496,500	70,724,900
Issuance of common stock:						
Exercise of employee stock options	511,584	5,100	511,700	-	-	516,800
Purchase of properties	100,000	1,000	549,000	-	-	550,000
Amortization of stock award	-	-	5,500	-	-	5,500
Repurchase and cancellation of treasury stock	(105,335)	(1,100)	(420,100)	-	-	(421,200)
Income tax benefit from the exercise of stock options	-	-	199,900	-	-	199,900
Net income	-	-	-	-	10,681,000	10,681,000
Balance December 31, 2000	16,244,044	$162,400	32,917,000	-	49,177,500	82,256,900

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW
YEARS ENDED DECEMBER 31, 2000, 1999, 1998

	2000	1999	1998
Cash flows from operating activities:			
Net income	$ 10,681,000	$ 7,824,300	$ 6,658,000
Adjustment to net income to reconcile to cash provided by operating activities:			
Deferred income taxes	1,838,300	108,900	244,000
Depreciation, depletion and amortization	6,943,500	4,031,200	3,253,600
(Gain) loss from sale of assets	(199,200)	(501,800)	18,700
Disposition of leasehold acreage	672,700	618,100	196,200
Amortization of stock award	5,500	12,200	12,200
Increase in notes and accounts receivable	(13,384,800)	(4,239,100)	(1,100,700)
(Increase) decrease in inventories	(520,300)	124,800	(404,500)
(Increase) decrease in prepaid expenses	(4,774,700)	312,600	(600)
Increase in other assets	(375,700)	(750,900)	(911,200)
Increase in accounts payable and accrued expenses	15,359,700	5,347,300	1,304,000
Increase (decrease) in advances for future drilling contracts	18,672,000	(3,183,400)	5,029,200
Increase (decrease) in funds held for future distribution	412,500	1,043,400	(675,500)
Total adjustments	24,649,500	2,923,300	6,965,400
Net cash provided by operating activities	35,330,500	10,747,600	13,623,400
Cash flows from investing activities:			
Capital expenditures	(27,932,100)	(27,758,200)	(26,629,700)
Proceeds from sale of leases	1,588,700	1,224,200	1,283,600
Proceeds from sale of fixed assets	680,100	651,000	56,300
(Increase) decrease in restricted cash	(2,324,000)	(458,100)	769,900
Net cash used in investing activities	(27,987,300)	(26,341,100)	(24,519,900)
Cash flows from financing activities:			
Proceeds from debt	8,050,000	9,300,000	-
Proceeds from issuance of stock	95,600	-	-
Net cash provided by financing activities	8,145,600	9,300,000	-
Net increase (decrease) in cash and cash equivalents	15,488,800	(6,293,500)	(10,896,500)
Cash and cash equivalents, beginning of year	28,444,900	34,738,400	45,634,900
Cash and cash equivalents, end of year	$ 43,933,700	$ 28,444,900	$ 34,738,400

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998

(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. An inventory of oil located in stock tanks on well locations, is carried at market at the end of each period.

OIL AND GAS PROPERTIES

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

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

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

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

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

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

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

TRANSPORTATION EQUIPMENT, PIPELINES AND OTHER EQUIPMENT

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. 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.

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

REVENUE RECOGNITION

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

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

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

INCOME TAXES

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

DERIVATIVE FINANCIAL INSTRUMENTS

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.

The Company has entered into an interest rate swap agreement to reduce its exposure to market risks from changing interest rates. The interest rate differential to be paid or received is accrued and recognized currently in interest expense.

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.

RECLASSIFICATIONS

Certain items and amounts reported in the 1999 and 1998 consolidated financial 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, 2000, 1999 and 1998.

NEW ACCOUNTING STANDARDS

Statement of Accounting Standards No. 133 and No. 138, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133/138), was issued by the Financial Accounting Standards Board. SFAS No. 133/138 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. The Company is required to adopt the provisions of SFAS 133/138 effective January 1, 2001. On adoption, the provisions of SFAS No. 133/138 must be applied prospectively. The natural gas futures and options and the interest rate swap agreement discussed in note 12 are derivatives pursuant to SFAS 133/138. The Company's derivatives will be treated as hedges of committed and/or anticipated transactions and have a total estimated fair value of $(20,131,800) on December 31, 2000. On January 1, 2001, the Company will record this estimated fair value as a liability with a corresponding adjustment to accumulated other comprehensive income (AOCI). The adjustment to AOCI will be recorded net of the related tax effects.

(2) NOTES AND ACCOUNTS RECEIVABLE

Included in other assets are noncurrent accounts receivable as of December 31, 2000 and 1999, in the amounts of $245,300 and $494,000 net of the allowance for doubtful accounts of $183,000 and $216,900, respectively.

The allowance for doubtful current accounts receivable as of December 31, 2000 and 1999 was $341,500 and $221,500, respectively.

(3) LONG-TERM DEBT

On August 29, 2000 the Company executed an Amendment to its Credit Agreement with Bank One, formerly First National Bank of Chicago. The amendment provides and the Company has activated a $30.0 million borrowing base, subject to adequate oil and gas reserves. 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, 2004.

As of December 31, 2000 and 1999 the outstanding balance was $17,350,000 and $9,300,000, respectively. 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. As of December 31, 2000 and 1999 the Company was in compliance with all financial covenants in the credit agreement.

At December 31, 2000, $10,000,000 of the outstanding balance was subject to an interest rate swap at a rate of 8.39%, $5,000,000 at a LIBOR rate of 8.52% and $2,350,000 was subject to a prime rate of 9.50%.

(4) INCOME TAXES

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

	2000	1999	1998
Current:			
Federal	$ 1,182,000	$ 1,434,300	$ 1,197,800
State	572,400	733,000	525,300
Total current income taxes	1,754,400	2,167,300	1,723,100
Deferred:			
Federal	1,415,600	(65,300)	(500)
State	422,700	174,200	244,500
Total deferred income taxes	1,838,300	108,900	244,000
Total taxes	$ 3,592,700	$ 2,276,200	$ 1,967,100

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

	2000 Amount	1999 Amount	1998 Amount
Computed "expected" tax	$ 4,853,100	$ 3,434,200	$ 2,932,500
State income tax	656,800	598,800	508,100
Percentage depletion	(758,300)	(612,000)	(343,400)
Nonconventional source fuel credit	(1,067,500)	(846,800)	(696,700)
Adjustments to valuation allowance	-	(375,000)	(473,200)
Other	(91,400)	77,000	39,800
	$ 3,592,700	$ 2,276,200	$ 1,967,100

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2000 and 1999 are presented below:

	2000	1999
Deferred tax assets:		
Allowance for doubtful accounts	$ 209,800	$ 175,400
Drilling notes	101,900	105,700
Alternative minimum tax credit carryforwards (Section 29)	2,132,300	1,982,300
Future abandonment	347,200	273,100
Deferred compensation	1,729,200	1,213,800
Other	49,400	51,600
Total gross deferred tax assets	4,569,800	3,801,900
Less valuation allowance	-	-
Deferred tax assets	4,569,800	3,801,900
Less current deferred tax assets (included in prepaid expenses)	(853,300)	(1,007,600)
Net non-current deferred tax assets	3,716,500	2,794,300
Deferred tax liabilities:		
Properties and equipment, principally due to differences in depreciation and amortization	(9,425,300)	(6,928,400)
Total gross deferred tax liabilities	(9,425,300)	(6,928,400)
Net deferred tax liability	$(5,708,800)	$(4,134,100)

The valuation allowance for the deferred tax assets as of January 1, 2000 and 1999 was $0 and $375,000, respectively. The net changes in the total valuation allowance were decreases of $375,000 and $473,200 for the years ended December 31, 1999 and 1998, respectively. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment.

At December 31, 2000, the Company has alternative minimum tax credit carryforwards (Section 29) of approximately $2,132,300 which are available to reduce future federal regular income taxes over an indefinite period.

(5) COMMON STOCK

OPTIONS

Options amounting to 180,000, 145,000 and 20,000 shares were granted during 2000, 1999 and 1998, 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 2000 and 1999 grants and a two year period for the 1998 grant. The outstanding options expire from 2005 to 2010

The estimated fair value of the options granted during 2000, 1999 and 1998 was $2.48, $2.44 and $3.92 per option, respectively. The fair value was estimated using the Black-Scholes option pricing model with the following assumptions for the 2000, 1999 and 1998 grant, respectively: risk-free interest rate of 6.13%, 5.1% and 5.9%, expected dividend yield of 0%, expected volatility of 57.31%, 61.3% and 58.0% and expected life of 7 years.

	Average Number of Shares	Range of Exercise Price	Exercise Prices
Outstanding December 31, 1997	1,872,650	$ 2.10	$ 0.94 - 5.13
Granted	20,000	$6.13	$ 6.13 - 6.13
Exercised	(324,333)	$0.94	$ 0.94 - .94
Expired	-	-	-
Outstanding December 31, 1998	1,568,317	$ 2.39	$ 0.94 - 6.13
Granted	145,000	$ 3.75	$ 3.75 - 3.75
Exercised	(324,333)	$ 0.94	$ 0.94 - .94
Expired	-	-	-
Outstanding December 31, 1999	1,388,984	$ 2.87	$ 0.94 - 6.13
Granted	180,000	$ 3.875	$3.875 - 3.875
Exercised	(511,584)	$ 1.01	$ 0.94 - 1.625
Expired	(12,400)	$ 3.31	$ 1.50 - 3.75
Outstanding December 31, 2000	1,045,000	$ 3.95	$1.125 - 6.125

As of December 31, 2000, there were 210,000 options outstanding and exercisable at the $1.125 exercise price which have a weighted average remaining contractual life of 4.9 years. Also as of December 31, 2000 there were 835,000 options outstanding and exercisable at a $3.75 to $6.13 exercise price range having a weighted average remaining contractual life of 7.4 years and weighted average exercise price of $4.66.

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:

	2000		1999	
	As Reported	Pro Forma	As Reported	Pro Forma
Net income	$ 10,681,000	$ 10,346,700	$ 7,824,300	$ 7,336,200
Basic earnings per share	$ 0.66	$ 0.64	$ 0.50	$ 0.47
Diluted earnings per share	$ 0.65	$ 0.63	$ 0.48	$ 0.45

STOCK REDEMPTION AGREEMENT

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

(6) EMPLOYEE BENEFIT PLANS

The Company made 401-K Plan contributions of $252,613, $217,400 and $202,600 for 2000, 1999 and 1998, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $1,000, $47,000 and $17,000, to the plan in cash during 2000, 1999 and 1998, respectively.

During 2000, 1999 and 1998 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 $5,500, $12,200 and $12,200 in 2000, 1999 and 1998, respectively.

At December 31, 2000 and 1999, the Company has recorded as other assets $360,000 and $300,000, 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 shares outstanding of 16,157,532 for 2000, 15,734,063 for 1999 and 15,505,680 for 1998.

Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding of 16,437,488 for 2000, 16,286,852 for 1999 and 16,338,298 for 1998. 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 $44,899,200 in 2000, $24,002,500 in 1999 and $22,997,300 in 1998 representing proceeds from the sale of oil and gas and made distributions to investor groups according to their working interests in the related oil and gas properties. Funds held for future distribution on the consolidated balance sheet includes amounts owed to affiliated partnerships as of December 31, 2000 and 1999.

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 $15,713,300 in 2000, $10,322,500 in 1999 and $9,621,700 in 1998 for those services. Amounts due from the partnerships as of December 31, 2000 and 1999 were $957,700 and $895,900, and are included in notes and accounts receivable.

During 2000, 1999 and 1998, the Company paid $40,400, $31,600 and $30,000, respectively to the Corporate Secretary's law firm for various legal services.

(9) COMMITMENTS AND CONTINGENCIES

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities and industrial customers. One customer, Cinnabar Energy Services, accounted for 11.3% of total revenues in 2000. No customer accounted for more than 10.0% of total revenues in 1999 or 1998.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's hedging instruments or the counterparties to the Company's gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses in 2000, 1999 or 1998.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may tender their partnership units for repurchase at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are tendered, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if tendered by the investors, is currently approximately $1,188,000. 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 $875,800, $124,200 and $0 for interest in 2000, 1999 and 1998, respectively. The Company paid income taxes in 2000, 1999 and 1998 in the amounts of $2,256,800, $1,327,800 and $2,349,100, respectively.

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

(11) ACQUISITIONS AND DIVESTITURES

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.

On December 15, 1999, the Company purchased all of the working interest in 53 producing wells in the D-J Basin of Colorado. At the date of acquisition, 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 3.0 Bcfe of proved undeveloped reserves.

Also included in the acquisition was 16.5 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.

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

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

(12) DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes commodity based derivative instruments as hedges to manage a portion of its exposure to price volatility stemming from its integrated natural gas production and marketing activities. These instruments consist of natural gas futures and option contracts traded on the New York Mercantile Exchange. 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, 2000 and 1999, the Company had futures contracts for the sale of 6,230,000 dt and 4,318,0000 dt of natural gas, respectively and option contracts for the sale of 2,276,400 dt as of December 31, 2000. While these contracts have nominal carrying value, their fair value, represented by the estimated amount that would be received (paid) upon termination of the contracts, based on market quotes, was a value of $(11,526,500) stemming from its marketing activities at December 31, 2000 and $350,500 stemming from its marketing activities at December 31, 1999. Based on the nature of the Company's gas marketing activities, hedging is not expected to have a significant impact on the Company's net margins from marketing activities during 2001. The fair value of these contracts was $(8,571,500) stemming from its natural gas production, $(5,142,900) net of tax at December 31, 2000.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2000 and 1999, cash in the amount of $2,938,300 and $614,300 was on deposit.

Interest rate swap agreements are used to reduce the potential impact of increases in interest rates on variable rate long-term debt. At December 31, 2000, the Company was a party to an interest rate swap agreement expiring on October 11, 2004. The agreement entitles the Company, on a quarterly basis, to a fixed-rate interest payment of 6.89% plus its current LIBOR rate margin (+1.50% At December 31, 2000) on a $10,000,000 notional amount related to its outstanding line of credit.

The fair value of the interest rate swap agreement was $(33,800), $(20,300) net of tax at December 31, 2000. Current market pricing models were used to estimate fair value.

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

(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,		
	2000	1999	1998
Property acquisition cost:			
Proved undeveloped properties	$ 3,397,500	$ 2,532,200	$ 1,903,200
Producing properties	8,361,400	6,997,500	8,679,000
Development costs	15,556,200	17,168,000	14,902,500
	$ 27,315,100	$ 26,697,700	$ 25,484,700

Of the above development costs incurred for the years ended December 31, 2000, 1999 and 1998 the amounts of $2,379,300, $2,977,500 and $2,657,700, respectively were incurred to develop proved undeveloped properties from the prior year end. The proved reserves attributable to these development costs were 1,388,200 Mcf and 83,900 bbls for 2000, 6,885,000 Mcf for 1999 and 5,787,000 Mcf for 1998 (amounts unaudited).

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,	
	2000	1999
Proved properties:		
Tangible well equipment	$ 82,304,400	$ 67,060,500
Intangible drilling costs	44,944,000	36,270,300
Undeveloped properties	4,023,500	2,507,100
	131,271,900	105,837,900
Less accumulated depreciation, depletion and amortization	29,739,500	23,652,000
	$101,532,400	$ 82,185,900

(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,		
	2000	1999	1998
Revenue:			
Oil and gas sales	$ 19,017,300	$ 8,628,400	$ 6,121,700
Expenses:			
Production costs	4,201,400	2,422,000	1,516,700
Depreciation, depletion and amortization	6,031,200	3,220,900	2,392,000
	10,232,600	5,642,900	3,908,700
Results of operations for oil and gas producing activities before provision for income taxes	8,874,700	2,985,500	2,213,000
Provision for income taxes	2,713,900	469,400	398,600
Results of operations for oil and gas producing activities (excluding corporate over-head and interest costs)	$ 6,070,800	$ 2,516,100	$ 1,814,400

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.

(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, 2000, 1999 and 1998. 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)		
	2000	**1999**	**1998**
Proved developed and undeveloped reserves:			
Beginning of year	1,154,000	29,000	45,000
Revisions of previous estimates	10,000	67,000	(10,000)
Beginning of year as revised	1,164,000	96,000	35,000
New discoveries and extensions			
Michigan	265,000	-	-
Wattenberg field	535,000	404,000	-
Dispositions to partnerships	(262,000)	-	-
Acquisitions			
Wattenberg field	573,000	652,000	-
Appalachian basin	-	10,000	2,000
Production	(109,000)	(8,000)	(8,000)
End of year	2,166,000	1,154,000	29,000
Proved developed reserves:			
Beginning of year	798,000	29,000	45,000
End of year	1,527,000	798,000	29,000

	Gas (MCF)		
	2000	**1999**	**1998**
Proved developed and undeveloped reserves:			
Beginning of year	101,245,000	80,819,000	57,243,000
Revisions of previous estimates	(3,859,000)	(4,475,000)	(3,517,000)
Beginning of year as revised	97,386,000	76,344,000	53,726,000
New discoveries and extensions			
Michigan	14,191,000	4,559,000	17,383,000
Wattenberg field	5,681,000	4,070,000	-
Piceance basin	8,922,000	9,974,000	-
Appalachian basin	266,000	6,178,000	6,169,000
Dispositions to partnerships	(8,498,000)	(8,774,000)	(6,009,000)
Acquisitions			
Michigan	-	-	2,842,000
Wattenberg field	5,761,000	5,546,000	-
Appalachian basin	668,000	6,799,000	9,161,000
Production	(5,737,000)	(3,451,000)	(2,453,000)
End of year	118,640,000	101,245,000	80,819,000
Proved developed reserves:			
Beginning of year	82,628,000	64,562,000	42,411,000
End of year	92,131,000	82,628,000	64,562,000

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

	Years Ended December 31,		
	2000	1999	1998
Future estimated cash flows	$520,010,000	$307,816,000	$186,598,000
Future estimated production costs	(144,505,000)	(104,233,000)	(84,078,000)
Future estimated development costs	(50,278,000)	(25,324,000)	(11,592,000)
Future estimated income tax expense	(80,982,000)	(39,930,000)	(20,322,000)
Future net cash flows	244,245,000	138,329,000	70,606,000
10% annual discount for estimated timing of cash flows	(139,606,000)	(79,875,000)	(40,412,000)
Standardized measure of discounted future estimated net cash flows	$104,639,000	$ 58,454,000	$ 30,194,000

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

	Years Ended December 31,		
	2000	1999	1998
Sales of oil and gas production, net of production costs	$ (14,816,000)	$ (6,206,000)	$ (4,605,000)
Net changes in prices and production costs	70,514,000	29,547,000	(23,083,000)
Extensions, discoveries and improved recovery, less related cost	73,636,000	39,653,000	18,615,000
Dispositions to partnerships	(16,850,000)	(6,152,000)	(5,762,000)
Acquisitions	27,907,000	31,915,000	13,938,000
Development costs incurred during the period	15,556,000	17,168,000	14,903,000
Revisions of previous quantity estimates	(5,925,000)	(4,944,000)	(5,605,000)
Changes in estimated income taxes	(41,052,000)	(19,608,000)	459,000
Changes in discount	(59,731,000)	(39,463,000)	1,224,000
Changes in production rates (timing) and other	(3,054,000)	(13,650,000)	(7,826,000)
	$ 46,185,000	$ 28,260,000	$ 2,258,000

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.

(18) BUSINESS SEGMENTS (THOUSANDS)

PDC's operating activities can be divided into three major segments: drilling and development, natural gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also engages in oil and gas sales to 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, 2000, 1999 and 1998 is as follows:

	2000	1999	1998
REVENUES			
Drilling and Development	$ 43,195	$ 42,116	$ 40,447
Natural Gas Sales	90,420	46,988	35,560
Well Operations	5,061	5,314	4,581
Unallocated amounts (1)	2,540	2,392	2,385
Total	$ 141,216	$ 96,810	$ 82,973

(1) Includes interest on investments and partnership management fees in 2000, 1999 and 1998 and gain on sale of assets in 2000 and 1999 which are not allocated in assessing segment performance.

	2000	1999	1998
SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and Development	$ 7,950	$ 6,608	$ 5,400
Natural Gas Sales	7,364	2,967	2,064
Well Operations	1,385	1,219	1,372
Unallocated amounts (2)			
General and Administrative expenses	(3,617)	(2,801)	(2,491)
Interest expense	(1,186)	(182)	-
Other (1)	2,378	2,289	2,280
Total	$ 14,274	$ 10,100	$ 8,625

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

	2000	1999	1998
SEGMENT ASSETS			
Drilling and Development	$ 31,592	$ 23,957	$ 27,288
Natural Gas Sales	139,116	93,073	65,256
Well Operations	8,490	7,977	7,136
Unallocated amounts			
Cash	1,567	1,967	7,814
Other	6,920	5,110	3,915
Total	$ 187,685	$ 132,084	$ 111,409

	2000	1999	1998
EXPENDITURES FOR SEGMENT LONG-LIVED ASSETS			
Drilling and Development	$ 3,217	$ 1,710	$ 1,953
Natural Gas Sales	23,958	24,613	23,645
Well Operations	650	1,328	947
Unallocated amounts	107	107	85
Total	$ 27,932	$ 27,758	$ 26,630

(19) QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 2000 and 1999, are as follows:

	2000				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$ 34,504,400	$ 29,063,200	$ 32,818,600	$ 44,830,300	$141,216,500
Cost of operations	29,600,900	25,225,800	28,646,900	38,666,300	122,139,900
Gross profit	4,903,500	3,837,400	4,171,700	6,164,000	19,076,600
General and administrative expenses	679,200	1,032,300	1,038,300	867,100	3,616,900
Interest expense	14,600	275,400	437,500	458,500	1,186,000
	693,800	1,307,700	1,475,800	1,325,600	4,802,900
Income before income taxes	4,209,700	2,529,700	2,695,900	4,838,400	14,273,700
Income taxes	968,300	581,900	555,000	1,487,500	3,592,700
Net income	$ 3,241,400	$ 1,947,800	$ 2,140,900	$ 3,350,900	$ 10,681,000
Basic earnings per share	$ 0.20	$ 0.12	$ 0.13	$ 0.21	$ 0.66
Diluted earnings per share	$ 0.20	$ 0.12	$ 0.13	$ 0.20	$ 0.65

	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	$ 0.17	$ 0.10	$ 0.13	$ 0.10	$ 0.50
Diluted earnings per share	$ 0.16	$ 0.10	$ 0.12	$ 0.10	$ 0.48

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

Stock Price History and Data

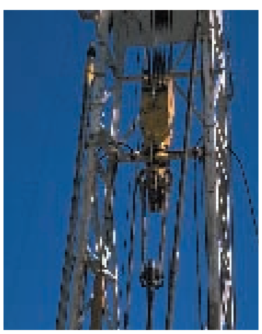
Petroleum Development Corporation's common stock trades on the over-the-counter market under the symbol PETD. The following table sets forth, for the periods indicated, the high and low bid quotations per share of the Company's common stock in the over-the-counter market, as reported by the National Quotation Bureau Incorporated. These quotations represent inter-dealer prices without real markups, markdowns, commissions or other adjustments and may not represent actual transactions.

	High	Low
1999		
First Quarter	$3.94	$2.88
Second Quarter	$4.69	$3.31
Third Quarter	$5.38	$4.19
Fourth Quarter	$4.81	$3.72
2000		
First Quarter	$4.45	$3.75
Second Quarter	$6.03	$3.88
Third Quarter	$7.13	$4.72
Fourth Quarter	$7.00	$5.19

As of December 31, 2000, there were approximately 1,266 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.

CORPORATE INFORMATION



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Petroleum Development Corporation
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304-842-5002

Petroleum Development Corporation
Locust Street Extension
Mahaffey, Pennsylvania 15757
814-277-6877

GLOSSARY OF TERMS USED IN THIS ANNUAL REPORT

Bbl	Barrel(s) of oil. One barrel of oil is equal to the energy equivalent of six Mcf of natural gas.
Bcf	Billion cubic feet of natural gas
Bcfe	Billion cubic feet of natural gas equivalent
EBITDA	Earnings before interest expense, income taxes, depreciation, depletion and amortization. A cash flow financial measure commonly used in the oil and gas industry.
MBbl	Thousand barrels of oil
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent of natural gas
MMBbl	Million barrels of oil
MMBoe	Million barrels of oil equivalent
MMcf	Million cubic feet of natural gas
MMcfe	Million cubic feet equivalent of natural gas
SEC PV-10	The value of proved reserves based on year-end commodity prices, discounted at 10 percent.

STOCK EXCHANGE LISTING

The company's common stock trades on The NASDAQ Stock Market, under the symbol "PETD."

PETD NASDAQ LISTED

DIRECTORS AND OFFICERS

James N. Ryan
Chairman and Chief Executive Officer

Steven R. Williams
President and Director

Dale G. Rettinger,
CFO, Executive Vice President,Treasurer and Director

Ersel E. Morgan
Vice President Production

Thomas E. Riley
Vice President Business Development

Eric R. Stearns
Vice President Exploration and Development

Darwin L. Stump
Controller

Vincent F. D'Annunzio
Director

Roger J. Morgan
Secretary and Director

Donald B. Nestor
Director

Jeffery C. Swoveland
Director

AUDITORS

KPMG LLP
Certified Public Accountants
Pittsburgh, Pennsylvania

LEGAL COUNSEL

Duane, Morris and Heckscher
Washington, District of Columbia

Young, Morgan & Cann
Clarksburg, West Virginia

INDEPENDENT RESERVOIR ENGINEERS

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TRANSFER AGENT

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Portland, Oregon 97204

Contact for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

FORM 10-K

A copy of the Annual Report of Petroleum Development Corporation to the Securities Exchange Commission (Form 10-K) may be obtained by writing to the company.