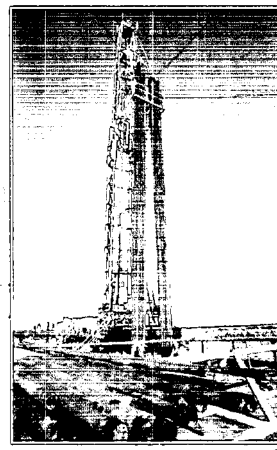
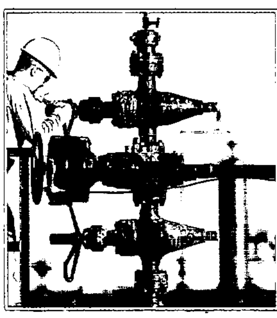
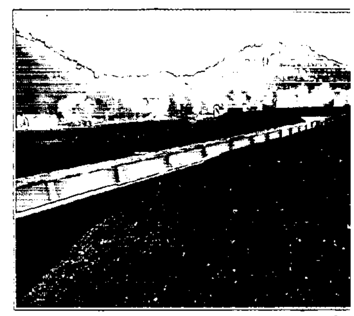
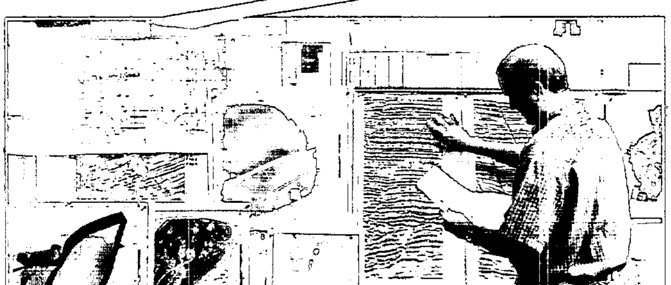
Penn Virginia Corporation

2002 Annual Report









Financial Highlights

In millions except per share data	**2002**	2001	2000
Financial Data			
Revenues[1]	**$ 111.0**	$ 96.6	$ 106.0
Operating Income[2]	**30.8**	1.6	65.7
Net Income[3]	**12.1**	34.3	39.3
Net Cash Flows Provided by Operating Activities	**65.8**	44.2	41.7
Common Share Data			
Net Income, Basic ($/share)	**$ 1.35**	$ 3.92	$ 4.76
Net Income, Diluted ($/share)	**1.34**	3.86	4.69
Dividends Paid ($/share)	**0.90**	0.90	0.90
Average Shares Outstanding	**9.0**	8.9	8.4
Capitalization			
Net Long-term Debt[4][5]	**106.9**	3.5	47.5
Minority Interest in Penn Virginia Resource Partners	**192.8**	144.0	—
Shareholder's Equity	**188.0**	185.5	171.2
Total Capitalization	**487.7**	333.0	218.7
Percent of Net Long-term Debt to Total Capitalization	**21.9%**	1.1%	21.7%
Summary Operating Data			
Production			
Oil and Condensate (Mbbl)	**349**	164	31
Natural Gas (Bcf)	**18.7**	13.1	11.6
Total Oil and Gas Production (Bcfe)	**20.8**	14.1	11.8
Coal Produced by Lessees (Millions of tons)	**14.3**	15.3	12.5
Realized Prices			
Oil and Condensate ($/Bbl)	**$ 23.63**	$ 22.94	$ 26.84
Natural Gas ($/Mcf)	**3.35**	4.06	3.95
Coal Royalties ($/Ton)	**2.20**	2.11	1.94
Estimated Reserves			
Oil and Condensate (MMbbl Proved)	**5.4**	3.9	0.1
Natural Gas (Bcf Proved)	**241.3**	229.3	174.2
Total Proved Oil and Gas Reserves (Bcfe)	**273.4**	252.8	174.7
Coal (Millions of Recoverable Tons)	**614.8**	492.8	480.0

(1) *Operating revenues, which exclude dividend income and gain on sale of properties, were $111.0 million, $95.9 million and $78.6 million for 2002, 2001 and 2000, respectively.*

(2) *Operating income in 2001 included a $33.6 million impairment on oil and gas properties. Operating income in 2000 included a $23.9 million gain on the sale of certain oil and gas properties.*

(3) *Net income in 2001 included a $54.7 million ($35.6 million after tax) gain on the sale of Norfolk Southern Corporation common stock.*

(4) *Net of $43.4 million cash equivalents held as collateral for the debt as of December 31, 2001.*

(5) *Included $90.9 million of long-term debt of PVR as of December 31, 2002.*

Penn Virginia Corporation (NYSE: PVA) is an energy company engaged in the acquisition, exploration, development and production of crude oil and natural gas. Through its ownership in Penn Virginia Resource Partners, L.P. (NYSE: PVR), PVA is also in the business of managing coal properties and related assets.

Abbreviations:

Bbl - Barrel
Bcf - Billion Cubic Feet
Bcfe - Billion Cubic Feet Equivalent
Mbbl - Thousand Barrels
MMbbl - Million Barrels
Mcf - Thousand Cubic Feet
Mcfe - Thousand Cubic Feet Equivalent
MMcf - Million Cubic Feet
MMcfe - Million Cubic Feet Equivalent
MMbtu - Million British Thermal Units

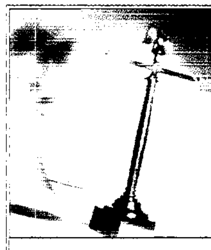
Year In Review

Penn Virginia Corporation's "Unique in Energy" strategy is to maintain a growing and balanced presence in both the upstream oil and gas industry as well as the coal land management business. Since its last Annual Report was written, the Company has made important advances in both of these core activities.

In August 2002, Penn Virginia entered into an agreement to develop Appalachian coalbed methane using a proprietary horizontal drilling technique with the potential to revolutionize the industry. In January 2003, the Company purchased approximately 32 Bcfe of oil and gas reserves which provide a significant and immediately accretive addition to its Gulf Coast operations.

In August 2002, Penn Virginia Resource Partners L.P. (NYSE:PVR), an MLP in which Penn Virginia is the general partner and owner of a 45 percent interest, purchased approximately 16 million tons of eastern coal reserves.

In December 2002, PVR acquired approximately 120 million tons of coal reserves from Peabody Energy Corporation. As part of the transaction, which included Peabody acquiring 15 percent of PVR, the companies formed an alliance for the purpose of pursuing additional growth opportunities.

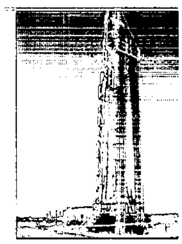


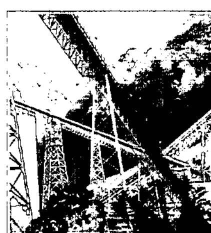
Governance

In an era of increased scrutiny of public companies, Penn Virginia ha been ahead of the curve in meeting the new rules regarding corpora governance. The Company has had a non-executive, independent Chairman of the Board since 1996. Six of the eight directors are independent. Each director has knowledge, experience and career sl directly related to one or both of the Company's businesses. The Auc Compensation and Benefits as well as the Nominating Committee are made up entirely of independent and qualified individuals as defined by the NYSE listing standards.

Oil and Gas

Penn Virginia Corporation drilled 65.5 net wells in 2002 of which 61.4 were successful. Oil and gas production increased over 2001 by 47 percent to 20.8 Bcfe. Over the past three years, production has grown at an annual compound average rate of 35 percent. Proven reserves were 273.4 Bcfe at year end 2002 and another 31.8 Bcfe of reserves were acquired in January 2003.



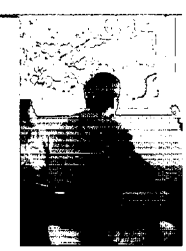


Coal Land Management

Penn Virginia has been in the coal royalty and land management business for 121 years. Since instituting its growth strategy in 1996, coal reserves owned or controlled by the Company have grown at a compound annual rate of 13 percent to 615 million t despite the mining of over 61 million tons from Company proper over the same period. Coal royalties from Penn Virginia reserves have increased at a compound annual rate of 24 percent since 1996.

People

Included in this 2002 Annual Report are pictures of some of Penn Virginia's 104 employees. We believe strongly the strength of any organization lies in the integrity, dedication and talents of its people. During 2002, Penn Virginia continued to add very qualified individuals to its outstanding and experienced team.



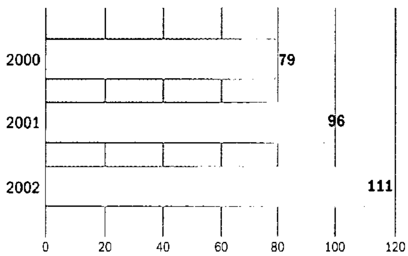
As an upstream supplier of natural gas, oil and coal, Penn Virginia is truly "unique in energy."

Dear Fellow Shareholder:
The rollercoaster ride in energy prices continued during 2002. This price volatility and economic uncertainty added to the challenges faced by the Company and also created opportunities for growth. Penn Virginia performed very well in this environment.

Revenue and cash flow from operations were all time highs for Penn Virginia in 2002. Oil and gas production reached a new high and was up 47 percent over 2001. At year end 2002, oil and gas reserves were a record 273 Bcfe, an increase of eight percent over 2001. Revenues and cash flows at Penn Virginia Resource Partners, L.P. ("PVR" or the "Partnership"), a master limited partnership controlled by the Company, were also at record levels.

From an operational and strategic perspective, 2002 was a year in which Penn Virginia focused on the execution of its action plan and continued to position itself for future growth. With an expanding presence in Gulf Coast oil and gas, an increasing inventory of

Operating Revenues*
Dollars in millions



Excludes dividend income and gain on sale of properties.

low risk natural gas prospects in the east and the completion of a vital alliance by PVR, for Penn Virginia, the best is yet to come.

Unique in Energy

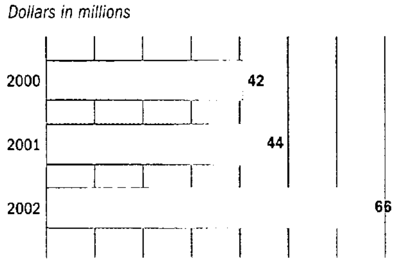
Since the late 1990's, Penn Virginia has been systemically and methodically putting in place the components necessary to build a different kind of energy company. The Company's underlying strategy is to develop a meaningful and growing presence in the upstream oil and gas industry (primarily natural gas) as well as to significantly increase the size and scope of its coal royalty and land management business. By being exposed to both segments of the energy industry, Penn Virginia benefits from the upside potential of the natural gas business while taking advantage of the historically more stable coal royalty business to maintain consistency in earnings and cash flow.

In 2001, the Company took two major steps in advancing its strategy. It acquired a significant set of Gulf Coast oil and gas assets, primarily in south Texas, which established Penn Virginia's presence outside the Appalachian basin and also provided a platform for further growth. The second step was to create a coal royalty-based master limited partnership (the "MLP"), Penn Virginia Resource Partners, L.P. This publicly-traded entity helped establish the market value of the Company's coal assets and provided a vehicle to facilitate future growth.

In 2002, Penn Virginia built on this foundation. Successes in exploiting the Gulf Coast assets led to year over year production increases of 6.0 Bcfe (or 274 percent) from the acquired assets. The Company's technical staff expanded, adding to Penn Virginia's industry exposure and generating new ideas and opportunities. One such opportunity was the South Texas property acquisition announced by the Company in January 2003. This outside-operated property has estimated proved reserves of 31.8 Bcfe net to Penn Virginia, and is expected to be immediately accretive to earnings and cash flow. The acquisition is expected to add five to seven Bcfe to Penn Virginia's 2003 production, an increase of 25 to 30 percent over the Company's average daily production in the fourth quarter of 2002. In addition, Penn Virginia believes the project has considerable upside potential. During 2002, the Company also added to its inventory of high quality 3D seismic data, increasing its seismic library from 300 square miles to what will become up to 1,500 square miles by early 2004.

Penn Virginia is continuing to focus on the low risk part of its portfolio. Using its knowledge of coal and experience in drilling and producing natural gas from tight formations, the Company has expanded its eastern presence. In August 2002, Penn Virginia entered into an agreement with CDX Gas LLC, a privately held oil and gas company, to develop coalbed methane gas reserves (CBM) in the Appalachian coal fields using a proprietary horizontal drilling technique. The area included in the agreement encompasses approximately 16,000 square miles, which is nearly all of central Appalachia and includes 500,000 acres of Penn Virginia leasehold. Two horizontal CBM well patterns were drilled on Penn Virginia property in 2002 with impressive results. Initial production from these patterns has been over 25 times what is typical from a traditional vertical CBM well drilled in similar coals. Penn Virginia and CDX are planning to drill six to eight additional horizontal patterns in 2003. The Company estimates it could have as many as two hundred drillable CBM prospects on its existing Appalachian leasehold.

Cash Flow From Operations
Dollars in millions



Penn Virginia expanded its low risk portfolio of drilling prospects in Mississippi, building on its previous successes in the Selma chalk. Modest CBM positions in the mid-continent and San Juan basin are being evaluated with the objective of adding to Penn Virginia's inventory of long lived, low risk natural gas reserves.

Penn Virginia Resource Partners, L.P. grew and added value in 2002. An acquisition of approximately 16 million tons of northern West Virginia coal reserves for $12 million was completed in August, adding an estimated 1.1 million tons per year to production. In December, the Partnership announced an important agreement with Peabody Energy Corporation (NYSE:BTU), the largest private sector coal producer in the world. As part of the transaction, Peabody sold to and leased back from PVR approximately 120 million tons of coal reserves. Approximately 80 million tons of these reserves are in New Mexico, and the balance is in northern West Virginia. The purchase was funded with $72.5 million of cash and 2.76 million newly-issued common partnership units. The transaction, which makes Peabody a significant (15 percent) unitholder, provides PVR with geographic diversity and creates a strategic alliance which could greatly enhance the MLP's ability to grow in the future.

Strategy

As discussed above, Penn Virginia's approach to the energy industry is to maintain a balance between its growing oil and gas and coal land management businesses. By diversifying its commodity exposure, the Company is striving to combine upside opportunity with downside protection for earnings and cash flow. The specific elements of Penn Virginia's strategy include:

- Maintain fiscal discipline. Avoid being over-leveraged, particularly in view of the significant reinvestment requirements of the oil and gas industry.
- Balance risk. An optimum portfolio has a full spectrum of risk/reward opportunities.
- Develop oil and gas prospects internally. Timely acquisitions are a part of the oil and gas business; however, better returns usually come from internally generated ideas.
- Build the coal land management MLP. A growth MLP requires a steady stream of accretive acquisitions.
- Be value, not size, driven. Size without value creation has little appeal.
- Hire and retain the best people.

A. James Dearlove
President and Chief Executive Officer

Robert Garrett
Chairman

Board Changes

During 2002, Penn Virginia lost the services of two well respected directors. In June, Mr. Richard A. Bachmann elected to leave the Board due to the increased demands of his growing company as well as Penn Virginia's increasing Gulf Coast presence which could have resulted in a conflict of interest. In December, Mr. Peter B. Lilly took a new position with a major coal company which caused him to relinquish his board seats with Penn Virginia and Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P. Both of these gentlemen made important contributions to Penn Virginia and will be missed.

Mr. H. Jarrell Gibbs joined the Board of Directors on December 4, 2002. Mr. Gibbs retired from TXU in June 2002 after a distinguished 20 year career during which he served as President and Vice Chairman of the $40 billion utility. His knowledge and experience in all aspects of the energy industry will be very beneficial to Penn Virginia.

Mr. Gary K. Wright joined the Board of Directors on January 7, 2003. Mr. Wright has 35 years of experience in energy finance and oil and gas production. He spent 28 years in commercial banking including a variety of senior management positions with Chase Manhattan Bank, Chemical Bank and Texas Commerce Bank. His in-depth knowledge of energy financing will serve the Company well.

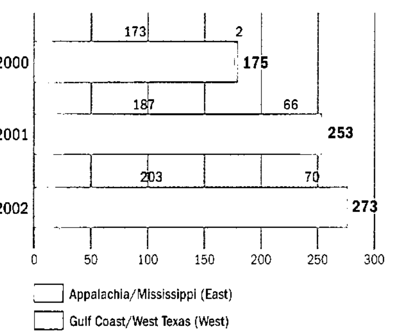
Outlook

As this letter is being written, there are clouds on the political and economic horizons. A war with Iraq has begun and the U.S. economic outlook remains uncertain. These factors and, of course, the weather, influence the performance of any company in the upstream energy business. However, there are positive signs for both the short and long term.

The price environment for natural gas appears extremely favorable. At the midpoint of the winter, gas storage levels were significantly below last year and lower than the five year average. Year over year gas production in 2002 was down an estimated six percent and, despite a $5.00/MMbtu market, the rig count remains constrained. Another indicator of gas supply problems is the diminishing additions in deliverability per rig. Canadian production is apparently declining and exports to Mexico are increasing. Lastly, liquified natural gas and supply from unconventional sources, such as CBM, are not expected to make up for the predicted production declines in the next few years.

In view of the difficult supply issues, a normal demand scenario should result in a sustained period of robust natural gas prices. Penn Virginia should benefit from those prices, since it has a solid inventory of high initial production rate prospects in the Gulf Coast and a large number of horizontal CBM locations. Complementing these shorter-lived oil and gas reserves are the long-lived, low risk conventional reserves in Appalachia and Mississippi as well as the very long-lived coal reserves owned by PVR.

Proved Oil & Gas Reserves
Bcfe



The coal industry endured a difficult year in 2002. Coming out of the extraordinarily warm winter of 2001/2002, average utility stockpiles were as much as 50 percent higher than normal. Today, even though stockpiles have come down, many coal burning utilities have delayed rebuilding inventories due to a liquidity crisis that has impacted much of the electricity generating sector. The difficulties in central Appalachia with permitting new mines and mine expansions have further weakened the region's coal industry.

Despite its problems, there is certainly hope for improvement in the coal industry. Although coal production in 2002 declined an estimated 2.5 percent nationwide and as much as six percent in central Appalachia, electricity usage increased approximately four percent in the same period. Electricity generation is the primary use of coal and most of the electricity generated in the U.S. comes from coal. Thus, a recovery in 2003 production appears likely.

During 2002, Penn Virginia Resource Partners, L.P. diversified away from its total dependence on central Appalachia by expanding into northern West Virginia and New Mexico. The Partnership significantly strengthened its lessee mix by entering into an alliance with Peabody Energy Corporation. The Peabody agreement results in approximately 30 percent of PVR's expected 2003 royalty revenue coming from one of the most stable and largest coal producers in the world. The agreement also provides incentives for Peabody to source additional assets to the Partnership, thereby helping to secure the MLP's future growth.

Despite making some important acquisitions and having record high oil and gas capital expenditures during 2002, Penn Virginia maintained a strong balance sheet and continues to have the financial capability to take advantage of new growth opportunities. At year end, the Company's consolidated debt to total capitalization was 22 percent when including as equity the minority interest owned by other holders of PVR common units.

During the past year, Penn Virginia focused on execution: building the Gulf Coast platform, strengthening its Appalachian and Mississippi oil and gas position as well as putting the MLP into a growth mode. For 2003, the Company's goals are to accelerate the horizontal CBM development program, increase the inventory of low risk oil and gas prospects, expand the Gulf Coast exploration and development program and take advantage of the momentum generated at PVR.

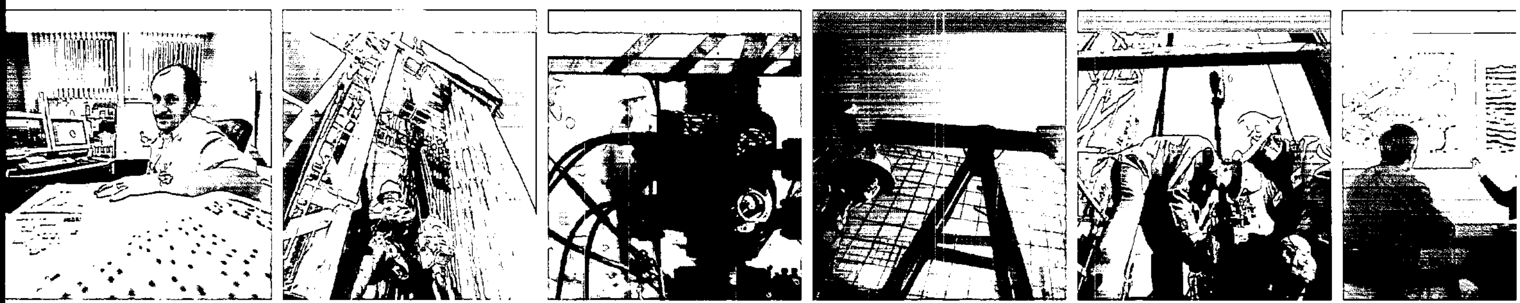
As always, the Company's success is a direct result of the efforts of its dedicated employees, and the loyalty and support of you, the shareholder.

James Dearlove

A. James Dearlove
President and Chief Executive Officer

R Garrett

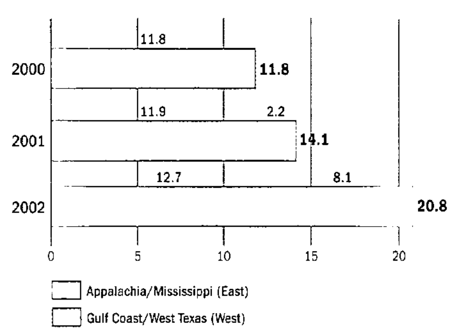
Robert Garrett
Chairman



Oil & Gas Operations

In 2002, Penn Virginia increased oil and gas production to 20.8 Bcfe, a 47 percent increase over 2001. Gulf Coast production totaled 8.1 Bcfe in 2002 and daily production in the fourth quarter of 2002 was 22.9 MMcfe per day, an 82 percent increase over the 12.6 MMcfe per day produced in the fourth quarter of 2001. Eastern production for 2002, including Appalachia and Mississippi, was up slightly to 12.7 Bcfe, a seven percent increase over 2001.

Oil & Gas Production
Bcfe



Penn Virginia's total proved reserves at the end of 2002 were 273 Bcfe, an increase of eight percent over 2001. Approximately 90 percent of the Company's reserves at year-end 2002 were natural gas. Penn Virginia replaced 206 percent of its production during 2002 at a reserve replacement cost of $1.32 per Mcfe.

During 2002, Penn Virginia expanded and enhanced its Appalachian oil and gas position by forming an area of mutual interest (AMI) with a private oil and gas company, CDX Gas LLC, for the purpose of producing coal bed methane gas reserves (CBM) using a proprietary horizontal drilling technique. The AMI includes 16,000 square miles including virtually all of central Appalachia. Penn Virginia owns 500,000 acres of leasehold within the AMI.

The horizontal drilling technology allows CBM wells to de-water much faster than vertical wells drilled in the same coals (two months compared to over eighteen months) and results in significantly higher production rates compared to vertical wells. A well drilled on Penn Virginia property in 2002 produced at a peak rate of 2.8 MMcf per day or over 25 times the 50 to 100 Mcf per day typical of a vertical well drilled in the same coals.

While an exciting and proven concept, horizontal drilling for CBM in Appalachia requires that issues of permitting, water disposal, infrastructure and specialized rig availability be addressed. Despite the hurdles, Penn Virginia intends to drill six to eight horizontal CBM wells in 2003 and ramp up to higher levels in the years to come.

During 2002, the Company also initiated development projects in two fields which target the Selma chalk formation in Mississippi, and conventional drilling initiatives were pursued to expand Penn Virginia's position in Appalachia.

Penn Virginia's oil and gas strategy is to maintain a balanced program combining low risk, moderate return development drilling in the East, a growing presence in CBM, and higher risk, higher return exploration and development drilling in the Gulf Coast.

A total of 80 gross (49.5 net) wells were drilled in the east (Appalachia and Mississippi) during 2002, including 77 gross (47.9 net) development wells and three gross (1.6 net) exploratory wells. The success rate on development wells was 99 percent and none of the exploratory wells were successful. In the Gulf Coast region, Penn Virginia drilled 13 gross (13 net) development wells in 2002 with a success rate of 85 percent and 3 gross (3 net) exploration wells were drilled, all of which were successful.

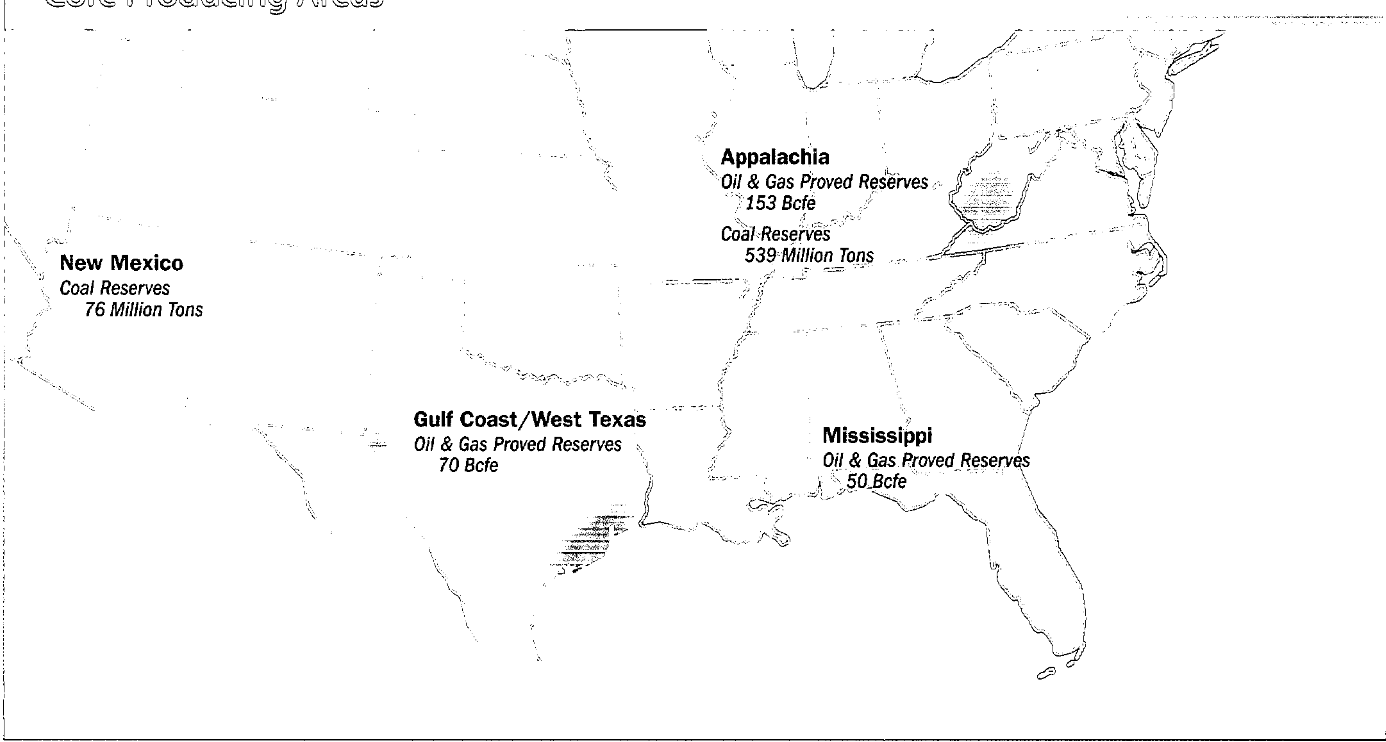
An important premise in Penn Virginia's approach to the oil and gas business is that internally generated ideas are critical to adding value. This approach requires a high quality staff and a sufficient inventory of seismic data. During 2002, the Company successfully built a first rate exploration staff which has over 200 years of combined experience in Gulf Coast operating areas. Penn Virginia also added to its 3D seismic library, increasing it from 300 square miles to what will be 1,500 square miles by early 2004. Further adding to the data base, an 80 square mile 3D seismic evaluation of a Company-owned field began late in 2002.

An underlying reason behind expanding into the Gulf Coast in 2001 was to establish a platform from which to grow. The successes and discoveries made on the acquired assets, and the successful extensions into surrounding areas indicate the viability of the strategy.

Commodity price hedging is an important part of Penn Virginia's financial strategy insofar as hedging increases the certainty of cash flow available for investment. The Company's policy is to hedge part of its existing oil and natural gas production as futures prices increase by specified amounts over trailing historical averages. As of January 31, 2002, the Company had natural gas hedges in place for 2003 covering approximately 22,000 MMbtu per day. These positions, generally in the form of costless collars, provide average floor and ceiling prices of $3.43 and $5.13 per MMbtu, respectively, and cover approximately one third of the Company's expected 2003 natural gas production. Approximately 450 barrels of oil per day are hedged for 2003 using costless collers at average floor and ceiling prices of $24.70 and $27.89 per barrel, respectively. Positions are also in place for 2004 covering approximately 10,000 MMbtu per day at floor and ceiling prices of $3.67 and $5.46 per MMbtu, respectively. Approximately 130 barrels of oil per day are hedged for 2004 at a price of $26.77 per barrel.

Penn Virginia's 2003 capital budget for oil and gas is approximately $75 to $85 million excluding acquisitions, with approximately 65 percent allocated to development drilling, 15 percent to exploratory drilling, 10 percent to increasing the seismic database and leasehold inventory, and the remainder to infrastructure and other projects.

Core Producing Areas



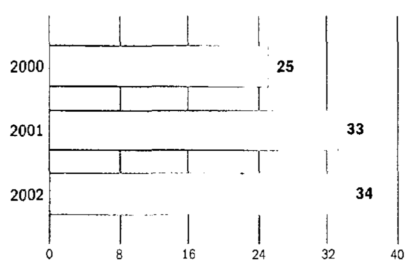
Coal Land Management

Penn Virginia is the general partner in the coal royalty-based master limited partnership, Penn Virginia Resource Partners, L.P., (PVR) which was brought public in October 2001. On December 31, 2002 Penn Virginia owned the general partner and 43 percent of the Partnership units.

As of December 31, 2002, PVR owns or controls approximately 615 million tons of coal reserves including an estimated 485 million tons in central Appalachia, 76 million tons in New Mexico and 54 million tons in northern Appalachia. The New Mexico and northern Appalachia reserves were acquired in 2002 in a pair of sale/leaseback transactions, including the alliance with Peabody Energy Corporation.

The move away from relying exclusively on central Appalachia coal was an important strategic step for PVR. The diversity of

Coal Royalties*
Dollars in millions



**Includes minimum rental income.*

markets and the Peabody alliance should help PVR maintain steady, reliable cash flows. The Partnership intends to continue its program of accretive acquisitions in multiple geographic regions.

In 2002, PVR had revenues from all sources of $38.6 million, a slight increase over the $37.5 million recorded in 2001 and a record for the Partnership. Coal royalties were $31.4 million, down 3 percent from 2001. Distributable cash flow in 2002 was $30.7 million, an increase of 40 percent over 2001. The increase was largely due to the tax efficiency of the MLP structure which was not in place for most of 2001. The Peabody transaction took place in mid-December and thus had a minimal effect on 2002 results.

In June 2001, PVR acquired the Fork Creek property in West Virginia, purchasing approximately 53 million tons of coal for $33 million. In early 2002, the operator at Fork Creek filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. Fork Creek's operations were idled on March 4, 2002. The operator continued to pay minimum royalties of $200,000 per month until PVR recovered its lease on August 31, 2002. In November 2002, PVR purchased various infrastructure located at Fork Creek including a newly constructed preparation plant and rail loadout facility for $5.1 million plus the assumption of certain reclamation liabilities. With control of the reserves, mining permits and critical infrastructure in hand, PVR's management is working diligently to put a financially stable operator in place. Although dependent on coal market conditions, management is confident a new lessee for Fork Creek will be found in a timely manner.

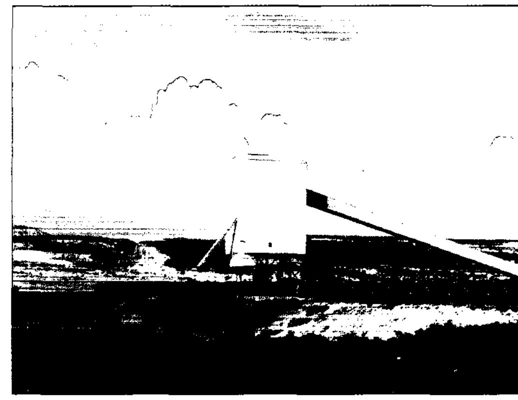
The Partnership's geographic diversity was greatly enhanced in 2002 due to its alliance with Peabody Energy. PVR intends to continue to expand into areas outside of central Appalachia.

Virtually all of the 2002 production from PVR's coal reserves came from Virginia and West Virginia. Virginia production was as expected and royalty realizations per ton were up slightly over 2001 due to contracts entered into by various lessees in the higher price environment of 2001.

West Virginia production was disappointing due to the difficulties at Fork Creek and the increasingly difficult regulatory conditions imposed on the industry. A judicial ruling regarding mountaintop removal mining resulted in a virtual paralysis with regard to coal mining permits being issued in the Huntington District of the Army Corps of Engineers which includes southern and central West Virginia as well as part of eastern Kentucky. The ruling, which singled out the coal industry, had a potentially devastating effect on the ability of coal mining companies to replace depleting operations or raise financing. On January 29, 2003 the mountaintop removal ruling was reversed by the U.S. Fourth Circuit Court of Appeals. The effect of this reversal should be positive, however, the speed at which permitting will resume is unknown.

Coal prices have been relatively weak throughout 2002. The extraordinarily warm winter of 2001/2002 and an unstable economy have both contributed to the weak prices. Since virtually all the coal burned in the U.S. is for electricity generation, with over 51 percent of the electricity generated in the U.S. coming from coal, the financial health of the country's utilities directly affects the coal industry. During 2002 the electric utility industry suffered through its worst liquidity crisis in decades. Thus, despite a warm summer in 2002 and a cold early winter in 2002/2003, utilities have delayed replenishing depleted coal stockpiles. However, in early 2003 there has been a solid recovery in eastern coal prices.

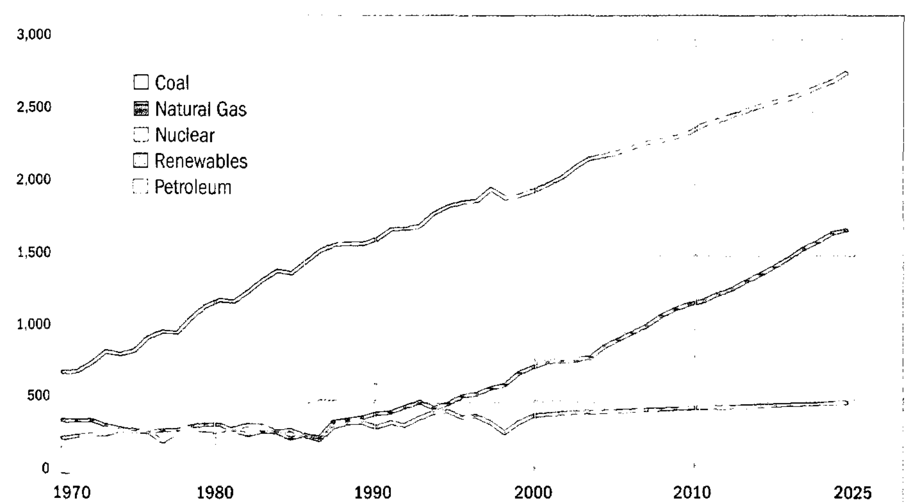
As a part of its coal land management activities, PVR is in the timber business. The Partnership typically sells cutting rights to various contractors who cut in advance of a mining project. To date, PVR has not entered the timber business as a stand-alone investment.



Timber revenues in 2002 were $1.6 million, which is about the same as the $1.7 million recorded in 2001. The slight drop-off resulted from a reduced cutting program and weakness in hardwood prices. Timber price increases are not forecasted for 2003 and PVR intends to sell only the timber necessary to accommodate its lessees' mining operations.

PVR also invests in coal-related infrastructure. To date these investments have been projects that directly aid the mining operations on PVR property. The Shober loadout facility, located in Virginia, shipped 2.4 million tons in 2002, generating revenue of $1.2 million. Two modular preparation plants, which save operators the expense of shipping raw coal long distances to be cleaned and thus allow marginal reserves to be mined economically, were brought on-line in 2002. The preparation plant and loadout facility at Fork Creek enhance the economic viability of the reserves, and are expected to generate positive returns for PVR. In the future, PVR expects to expand this fee-based part of its business.

Electricity Generation by Fuel, 1970-2025
Billion Kilowatthours



Coal and natural gas usage is expected to grow well into the future and Penn Virginia is well-positioned to share in that growth.
Source: Energy Information Administration

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

__X__ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2002

Commission File Number 001-13283

PENN VIRGINIA CORPORATION
One Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, PA 19087

Registrant's telephone number, including area code: (610) 687-8900

Incorporated in VIRGINIA	I.R.S Employer Identification Number 23-1184320

Securities registered pursuant to section 12(b) of the Act: None

Securities Registered pursuant to Section 12(g) of the Act:

Title of Each Class	Name of Exchange on which registered
Common Stock, $6.25 Par Value	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ____

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter. $348,612,796.

As of February 27, 2003, 8,947,418 shares of common stock of the registrant were issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

	Part Into Which Incorporated
(1) Proxy Statement for Annual Shareholders Meeting on May 6, 2003	Part III

Penn Virginia Corporation and Subsidiaries

Part I

Item 1 ⇒ Business

General

Penn Virginia Corporation ("Penn Virginia" or the "Company") is a Virginia corporation founded in 1882. We are engaged in the exploration, development and production of oil and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. We also collect royalties on various oil and gas properties in which we own a mineral fee interest. At December 31, 2002, we had proved reserves of approximately 5.4 million barrels of oil and condensate and 241 billion cubic feet (Bcf) of natural gas, or 273 billion cubic feet equivalent ("Bcfe").

Until October 30, 2001, we also engaged directly in the leasing and management of coal properties in the Central Appalachian region of the United States. In September 2001, we transferred our coal properties and related assets and liabilities to Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a newly formed Delaware limited partnership. On October 30, 2001, the Partnership completed its initial public offering ("IPO") of approximately 7.5 million common units at $21.00 per unit, which are traded on the New York Stock Exchange under the symbol PVR. At December 31, 2002, the Partnership owned approximately 615 million tons of proven and probable coal reserves, including approximately 120 million tons of such reserves that were acquired in December 2002 related to a strategic alliance with Peabody Energy Corporation ("Peabody"). The Partnership's coal reserves are located on 241,000 acres in Virginia, West Virginia, New Mexico and eastern Kentucky. The Partnership does not operate any mines, but has leased its reserves under 51 leases to 28 different operators who mine coal at 61 mines in exchange for royalty payments to PVR. Lessees other than those which are affiliates of Peabody (the "Peabody Lessees") are generally required to make royalty payments to the Partnership based on the amount of coal they produce from the Partnership's properties and the price at which they sell the coal, subject to fixed minimum royalty rates per ton. The Peabody Lessees are required to make payments based on fixed royalty rates which escalate annually. In managing its properties, PVR actively works with its lessees to develop efficient methods to exploit reserves and to maximize production from properties. Additionally, the Partnership provides fee-based coal preparation and transportation facilities to some of its lessees to generate coal service revenues. The Partnership also generates timber sales from timber owned. The Partnership owned approximately 168 million board feet ("MMbf") of timber at December 31, 2002.

Our wholly owned subsidiary, Penn Virginia Resource GP, LLC, a Delaware limited liability company, serves as general partner of the Partnership. As of December 31, 2002, we owned approximately 45 percent of the Partnership, consisting of a two percent general partner interest, 42 percent subordinated units, and one percent common units. As part of our ownership of PVR's general partner, we also own the rights, referred to as Incentive Distribution Rights, to receive an increasing percentage of quarterly distribution of available cash from operating surplus after certain levels of cash distributions have been achieved. See Item 1 – Business – Corporate and Other, for more information on Incentive Distribution Rights.

Financial Information

We operate in two primary business segments. We are in the oil and natural gas exploration and production business and, through our interests in PVR, we are in the coal royalty and land management business. For financial statement purposes, the assets, liabilities and earnings of PVR are included in our consolidated financial statements, with the public unitholders' ownership interest reflected as a minority interest. See Note 19 (Segment Information) of the Notes to the Consolidated Financial Statements, for financial information concerning our business segments.

Oil and Gas Operations

General

Our oil and gas properties are located primarily in the eastern and Gulf Coast onshore areas of the United States. At December 31, 2002, we had 273 Bcfe of proved reserves (88 percent natural gas) including 226 Bcfe held through various working interests and 47 Bcfe held by royalty interests. During 2002, 349 thousand barrels of oil and condensate and 18.7 Bcf of natural gas, net to our interest, were produced from continuing operations compared with 164 thousand barrels and 13.1 Bcf in 2001. In addition, there were approximately 18 thousand barrels of oil and condensate and 16 million cubic feet ("MMcf") of natural gas produced from properties which were sold in 2002 and reflected as discontinued operations. We received average prices of $23.63 and $22.94 per barrel and $3.35 and $4.06 per thousand cubic feet ("Mcf") for crude oil and natural gas sales in 2002 and 2001, respectively. We also drilled 96 gross (65.5 net) wells in 2002, of which 90 gross (60.9 net) were development and 6 gross (4.6 net) were exploratory. A total of 3 gross (1.6 net) exploratory wells were not successful.

Transportation

The majority of our natural gas production is transported to market primarily on three major transmission systems. Duke Energy, Inc., Nisource, Inc. and Dominion Energy, Inc. transported 39 percent, 24 percent and 20 percent, respectively, of our 2002 natural gas production. The remainder was divided among several pipeline companies in Texas, Louisiana and West Virginia. In almost all cases, our natural gas is sold at the interconnects with the transmission pipelines. For additional information, see Item 1 – Risks Associated with Business Activities – Oil and Gas – Transportation.

Marketing and Hedging

We generally sell our natural gas using the spot market and short-term fixed price physical contracts. From time to time, we enter into commodity derivative contracts or fixed price physical contracts to mitigate the risk associated with the volatility of natural gas prices. Recently, we have utilized swaps and costless collars in connection with our hedging activities. Gains and losses from hedging activities are included in revenues when the hedged production is sold. We recognized a loss of $1.0 million on settled hedging activities in 2002, a gain of $1.9 million in 2001, and no gain or loss in 2000. In 2002, we hedged approximately 44 percent of our natural gas base production at an average NYMEX Henry Hub floor price of $2.98 per MMbtu and a ceiling price of $3.53 per MMbtu. For crude oil, we hedged approximately 76 percent of our 2002 crude oil production at an average floor price or $21.31 per barrel and a ceiling price of $25.72 per barrel. See Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Quantitative and Qualitative Disclosures about Market Risk, for information about our price risk management positions for 2003, 2004 and the first quarter of 2005.

Coalbed Methane Drilling Venture

In August 2002, we entered into an agreement with CDX Gas, LLC ("CDX"), a private owner of proprietary horizontal drilling technology, to explore for and develop coalbed methane ("CBM") in 16,000 square miles of property located in Central Appalachia as well as in the Devonian Shale formation. Our agreement with CDX is generally for five years and provides that we and CDX will have a 60 percent and 40 percent working interest, respectively, in future CBM projects conducted on property owned by us and subject to the agreement. On future projects conducted on property not owned by us, we and CDX will generally each have a 50 percent working interest.

Coal Royalty and Land Management Operations

Overview

At December 31, 2002, the Partnership owned and leased approximately 241,000 acres in Virginia, West Virginia, New Mexico and eastern Kentucky containing approximately 615 million tons of coal reserves. The Partnership earns coal royalty revenue, based on long-term lease agreements, from 28 coal-mining operators actively mining under 51 separate leases at 61 mines. Coal royalty revenues under non-Peabody leases are based on the higher of a percentage of the gross sales price or a fixed price per ton of coal, with pre-established minimum monthly or annual payments. Under the Peabody leases, coal royalty revenues are based on fixed royalty rates which escalate annually, also with pre-established monthly minimums. The Partnership does not operate coal mines. The Partnership provides fee-based coal preparation and transportation facilities to some of its lessees to enhance their production levels and generate additional coal service revenues.

The Partnership's timber assets consist of various hardwoods, primarily red oak, white oak, yellow poplar and black cherry. The Partnership owned approximately 168 million board feet of standing saw timber at December 31, 2002. The Partnership's timber inventory only includes timber that can be harvested and is greater than 12 inches in diameter.

In December 2002, the Partnership announced the formation of an important strategic alliance with Peabody Energy Corporation, the largest private sector coal company in the world. Central to the transaction was the purchase from and leaseback to Peabody of approximately 120 million tons of coal reserves located in New Mexico (80 million tons) and northern West Virginia (40 million tons) (the "Peabody Acquisition"). As a result of the Peabody Acquisition, the Partnership's total reserves increased by approximately 25 percent to 615 million tons. The Peabody Acquisition was funded with $72.5 million in cash and the issuance by the Partnership to Peabody of 1,522,325 common units and 1,240,833 Class B common units. Of the Class B common units issued, 293,700 are currently being held in escrow pending certain approvals from the State of New Mexico and Peabody's acquisition and transfer to PVR of certain reserves. As a result of the escrow arrangement, approximately five million tons of coal reserves were excluded from reserve totals and 293,700 Class B common units were excluded from units issued in the Partnership's financial statements for the year ended December 31, 2002.

The alliance with Peabody accomplishes several strategically important goals. It provides geographic diversity by exposing the Partnership to new markets in the western United States and northern Appalachia. The inclusion of affiliates of Peabody as a significant part of the Partnership's lessee mix adds additional strength and stability to its lessee group. Peabody is incentivized to source additional assets to the Partnership in the future. This incentive is derived not only from Peabody's ownership of approximately 15 percent of the Partnership's common units, but also from its right to share in the general partner's incentive distribution rights if Peabody sells additional coal assets to the Partnership in the future. See Item 1 – Corporate and Other – Partnership Distributions, Incentive Distribution Rights for more information.

In addition to the Peabody Acquisition, in August 2002, the Partnership purchased approximately 16 million tons of coal reserves in northern Appalachia for $12 million. This acquisition was the Partnership's first outside of central Appalachia. The properties, which include approximately 18,000 mineral acres, contain predominately high sulfur, high BTU coal reserves.

In June 2001, the Partnership acquired the Fork Creek property in West Virginia, purchasing approximately 53 million tons of coal reserves for $33.1 million. In early 2002, the operator at Fork Creek filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code and operations at the mine were idled on March 4, 2002. The operator continued to pay minimum royalties until the Partnership recovered its lease on August 31, 2002. In November 2002, the Partnership purchased various infrastructure at Fork Creek for $5.1 million plus the assumption of certain reclamation liabilities and stream mitigation obligations. With control of the reserves, permits and the critical infrastructure, PVR's management is working diligently to put a new, financially stable operator in place at Fork Creek. As is customary in the Partnership's operations, PVR intends to assign all related reclamation liabilities to the new operator.

Coal Royalties

The Partnership's lessees mined approximately 14.3 million tons of coal in 2002 from PVR's properties and paid an average royalty of $2.20 per ton, compared with approximately 15.3 million tons mined in 2001 at an average royalty of $2.11 per ton.

Timber Sales

Timber is harvested in advance of lessee mining to prevent loss of the resource. Timber is sold as individual parcels in competitive bid sales or on a contract basis, where PVR pays independent contractors to harvest timber while PVR directly markets the product. The Partnership sold approximately 8.3 MMbf in 2002 at an average price of $187 per thousand board feet ("Mbf"), compared with 8.7 MMbf at an average price of $168 per Mbf in 2001.

Coal Services

The Partnership generates coal service revenues from fees charged to lessees for the use of the Partnership's coal preparation and transportation facilities. The majority of these fees have been generated by the Partnership's unit train loadout facility, which was completed in April 1999 at a cost of $5.2 million. This facility accommodates 108-car unit trains, which can be loaded in approximately four hours. Lessees utilize the unit train loadout facility to reduce delivery costs incurred by their customers. The Partnership recognized $1.7 million in coal service revenues in 2002 and 2001. Such amounts are reported in other revenues in the Consolidated Statements of Income included herein.

Corporate and Other

Partnership Distributions

We are entitled, through our wholly owned subsidiaries, to receive certain cash distributions payable with respect to the subordinated and common units of PVR held by such subsidiaries as well as certain cash distributions payable with respect to general partner incentive distribution rights held by our general partner subsidiary.

Cash Distributions. The Partnership made its first cash distribution of $0.34 per common and subordinated unit in February 2002 for the period October 30, 2001 through December 31, 2001. For 2002, the Partnership made quarterly cash distributions of $0.50 per common unit and subordinated unit. The Partnership intends to increase quarterly cash distributions to $0.52 per common unit and subordinated unit beginning with the distribution payable in May 2003 with respect to the first quarter of 2003.

Incentive Distribution Rights. Our wholly owned subsidiary is the general partner of PVR and, as such, holds certain incentive distribution rights which represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the Partnership has paid minimum quarterly distributions and certain target distribution levels have been achieved. The minimum quarterly distribution is $0.50 per unit ($2.00 per unit on an annual basis). The incentive distributions rights are payable as follows:

If for any quarter:

- PVR has distributed available cash from operating surplus to its common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- PVR has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, PVR will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner subsidiary in the following manner:

- First, 98 percent to all unitholders, pro rata, and 2 percent to the general partner, until each unitholder has received a total of $0.55 per unit for that quarter;
- Second, 85 percent to all unitholders, and 15 percent to the general partner, until each unitholder has received a total of $0.65 per unit for that quarter;
- Third, 75 percent to all unitholders, and 25 percent to the general partner, until each unitholder has received a total of $0.75 per unit for that quarter; and
- Thereafter, 50 percent to all unitholders and 50 percent to the general partner.

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution on the common units. In conjunction with the Peabody

Acquisition, our general partner subsidiary has issued a special membership interest which entitles Peabody to receive increased percentages, starting at zero and increasing up to 40 percent, of payments PVR makes to our general partner subsidiary with respect to incentive distribution rights if PVR purchases additional assets from Peabody in the future.

Investments

During 2001, we sold 3,307,200 shares of Norfolk Southern Corporation (NYSE: NSC) common stock. The shares were sold in open market transactions on the New York Stock Exchange at an average price of $17.39 per share. Our 3,307,200 common shares of Norfolk Southern Corporation generated dividends of $0.2 million in 2001 and $2.6 million in 2000. We received a quarterly dividend of $0.06 per share in 2001, which was a reduction from the $0.20 per share realized in 2000. We had no available-for-sale securities at December 31, 2002 and 2001. See Note 5 (Investments and Dividend Income) of the Notes to the Consolidated Financial Statements for additional information.

Risks Associated with Business Activities

Oil and Gas

Competition

The oil and natural gas industry is very competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position depends on our geological, geophysical and engineering expertise, our financial resources, our ability to develop properties and our ability to select, acquire and develop proved reserves. We compete with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. We also compete with major and independent oil and gas companies in the marketing and sale of oil and natural gas, and the oil and natural gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. We compete with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time.

Price Volatility

Historically, natural gas and crude oil prices have been volatile. These prices rise and fall based on changes in market demand and changes in the political, regulatory and economic climate and other factors that affect commodities markets that are generally outside of our control. Some of our projections and estimates are based on assumptions as to the future prices of natural gas and crude oil. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future may differ from our estimates. Any substantial or extended decline in the actual prices of natural gas and/or crude oil could have a material adverse effect on the Company's financial position and results of operations (including reduced cash flow and borrowing capacity), the quantities of natural gas and crude oil reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Drilling and Operating Risks

Our drilling operations are subject to various risks common in the industry, including cratering, explosions, fires and uncontrollable flows of oil, gas or well fluids. Our drilling operations are also subject to the risk that no commercially productive natural gas or oil reserves will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including drilling conditions, pressure or irregularities in formations, equipment failures or accidents and adverse weather conditions.

Transportation

We transport our natural gas to market on various gathering and transmission pipeline systems owned by third parties. Gathering fees are primarily paid by the purchaser of the natural gas. The majority of natural gas sales contracts are one year or less in duration and contain relevant monthly index pricing provisions. Interruptible gathering rates have increased over the years as pipelines have implemented the mandatory unbundling of gathering services (Federal Energy Regulatory Commission Order 636) from other transportation services. In 2002, Duke Energy, Inc. gathered and transported approximately 39 percent of our natural gas, Nisource, Inc. (formerly Columbia Gas Transmission) approximately 24 percent, and Dominion Energy, Inc. approximately 20 percent, with the remainder divided among several pipeline companies in Texas, West Virginia and Louisiana. Production could be adversely affected by shutdowns of the pipelines for maintenance or replacement as transportation options are limited.

Regulation

State Regulatory Matters. Various aspects of our oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas. These provisions include the permitting for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. The effect of these regulations is to limit the amounts of crude oil and natural gas we can produce from our wells, and to limit the number of wells or the locations at which we can drill.

Federal Energy Regulatory Commission. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In the past, the Federal government has regulated the prices at which oil and gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 (the "Decontrol Act") removed all NGA and NGPA price and nonprice controls affecting producers' wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids can currently be made at market prices, Congress could reenact price controls in the future.

Commencing in April 1992, the FERC issued Order Nos. 636, 636-A, 636-B and 636-C ("Order No. 636"), which require interstate pipelines to provide transportation separate, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all gas supplies. Although Order No. 636 does not directly regulate gas producers like Penn Virginia Corporation, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. In particular, the FERC has issued Order No. 637, which, among other things, (i) permits pipelines to charge different maximum cost-based rates for peak and off-peak times, (ii) encourages auctions for pipeline capacity, (iii) requires pipelines to implement imbalance management services, and (iv) restricts the ability of pipelines to impose penalties for imbalances, overruns, and non-compliance with operational flow orders. In addition, the FERC has implemented regulations governing the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement, which it largely affirmed in a recent order on rehearing, establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates based solely on the costs associated with such new pipeline facilities.

While any additional FERC action on these matters would affect us only indirectly, these changes are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC will take on these matters, nor can we predict whether the FERC's actions will achieve its stated goal of increasing competition in natural gas markets. However, we do not believe that we will be treated materially differently than other natural gas producers and markets with which we compete.

Environmental Matters. Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

Coal Royalty and Land Management

Although the Partnership intends to make quarterly cash distributions of $0.52 per common unit, it can only do so to the extent it has sufficient cash from operations after payment of fees and expenses.

In addition, quarterly distributions are payable on our subordinated units only after each common unit has received a distribution of $0.52 plus any arrearages due from prior quarters. Incentive distributions are payable to our general partner subsidiary after cash distributions per unit exceed $0.55 in any quarter. The Partnership's revenues and its ability to make quarterly and incentive distributions are subject to several risks, including those described below.

Competition

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. The Partnership's lessees compete with coal producers in various regions of the U.S. for domestic sales. The industry has undergone significant consolidation that has led to some of the competitors of the Partnership's lessees located in Appalachia to have significantly larger financial and operating resources than the Partnership's lessees do. The Partnership's lessees primarily compete with both large and small producers in Appalachia as well as the western United States. They compete on the basis of coal price at the mine, coal quality (including sulfur content), transportation cost from the mine to the customer and the reliability of supply. Continued demand for the Partnership's coal and the prices that the Partnership's lessees obtain are also affected by demand for electricity, environmental and government regulations, technological developments and the availability and price of alternative fuel supplies, including nuclear, natural gas, oil and hydroelectric power. Demand for the Partnership's low sulfur coal and the prices the Partnership's lessees will be able to obtain for it will also be affected by the price and availability of high sulfur coal, which can be marketed in tandem with emissions allowances in order to meet federal Clean Air Act requirements.

Operating Risks

General Regulation. The Partnership's lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws, and management of electrical equipment containing polychlorinated biphenyls, or PCBs. Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by the Partnership's lessees can be eliminated completely. However, none of the violations to date, or the monetary penalties assessed, have been material to us, to the Partnership or, to our knowledge, to the Partnership's lessees. We do not currently expect that future compliance will have a material adverse effect on us or the Partnership.

While it is not possible to quantify the costs of compliance by the Partnership's lessees with all applicable federal and state laws, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. The Partnership does not accrue for such costs because its lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, the Partnership does require some smaller lessees to deposit certain funds into escrow for reclamation and mine closure costs or post performance bonds for these costs. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the utility industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities which could affect demand for the Partnership's lessees' coal. The possibility exists that new legislation or regulations may be adopted which may have a significant impact on the mining operations of the Partnership's lessees or their customers' ability to use coal and may require the Partnership, its lessees or their customers to change operations significantly or incur substantial costs.

Regulation

Clean Air Act. The Clean Air Act affects the end-users of coal and could significantly affect the demand for the Partnership's coal and reduce the Partnership's coal royalty revenues. The Clean Air Act and corresponding state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides and other compounds emitted from industrial boilers and power plants, including those that use the Partnership's coal. These regulations together constitute a significant burden on coal customers and stricter regulation could further adversely impact the demand for and price of the Partnership's coal, resulting in lower coal royalty revenues.

In July 1997, the U.S. Environmental Protection Agency adopted more stringent ambient air quality standards for particulate matter and ozone. Particulate matter includes small particles that are emitted during the combustion process. In a February 2001 decision, the U.S. Supreme Court largely upheld the EPA's position, although it remanded the EPA's ozone implementation policy for further consideration. Details regarding the new particulate standard itself are still subject to judicial challenge. These ozone restrictions will require electric power generators to further reduce nitrogen oxide emissions. Nitrogen oxides are naturally occurring byproducts of coal combustion that lead to the formation of ozone. Further reduction in the amount of particulate matter that may be emitted by power plants could also result in reduced coal consumption by electric power generators. Future regulations regarding ozone, particulate matter and other ambient air standards could restrict the market for coal and the development of new mines by the Partnership's lessees. This in turn may result in decreased production by the Partnership's lessees and a corresponding decrease in the Partnership's coal royalty revenues. These decreases could adversely effect the distributions we receive from the Partnership.

The Clean Air Act also imposes standards on sources of hazardous air pollutants. These standards have not yet been extended to coal mining operations or by-products of coal combustion, but consideration is now being given to regulating certain hazardous air pollutant components that are found in coal combustion exhaust, including mercury. Like other environmental regulations, these standards and future standards could result in a decreased demand for coal.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 ("SMCRA") and similar state statutes impose on mine operators the responsibility of restoring the land to its original state or compensating the landowner for types of damages occurring as a result of mining operations, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations. Regulatory authorities may attempt to assign the liabilities of the Partnership's lessees to the Partnership if any of the lessees are not financially capable of fulfilling those obligations. In conjunction with mining the property, the Partnership's lessees are contractually obligated under the terms of their leases to comply with all laws, including SMCRA and equivalent state and local laws, which obligations include reclaiming and restoring the mined areas by grading, shaping and reseeding the soil. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan.

CERCLA. The Partnership could become liable under federal and state Superfund and waste management statutes if its lessees are unable to pay environmental cleanup costs. The Comprehensive Environmental Response, Compensation and Liability Act, known as CERCLA or "Superfund," and similar state laws create liabilities for the investigation and remediation of releases and threatened releases of hazardous substances to the environment and damages to natural resources. As a landowner, the Partnership is potentially subject to liability for these investigation and remediation obligations.

Mountaintop Removal Litigation. On January 29, 2003, the United States Fourth Circuit Court of Appeals (the "Circuit Court") vacated an injunction issued in May 2002 by the United States District Court for the Southern District of West Virginia (the "District Court"). This injunction had prohibited the Huntington, West Virginia office of the U.S. Army Corps of Engineers (the "Corps") from issuing permits under Section 404 of the Clean Water Act for the construction of valley fills for the disposal of coal mining overburden. These valleys typically contain steams that, under the Clean Water Act, are considered navigable waters of the United States. The District Court had found that the Corp's permitting of overburden valley fills under Section 404 was a violation of the Clean Water Act since Section 404 allows only the permitting of fill material deposited for a beneficial purpose and not for mere waste disposal such as the disposal of coal overburden. The Circuit Court reversed this finding, concluding, instead, that overburden valley fills may be permitted under Section 404 and remanded the case back to the District Court for further proceedings not inconsistent with the Circuit Court's opinion.

Mine Health and Safety Laws. Stringent safety and health standards have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive safety and health standards on all mining operations. In addition, as part of the Mine Health and Safety Acts of 1969 and 1977, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung and to some survivors of a miner who dies from this disease.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, the Partnership's lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including the Partnership's lessees, must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically lessees submit the necessary permit applications between 12 and 18 months before they plan to begin mining a new area. In the Partnership's experience, permits generally are approved within 12 months after a completed application is submitted. In the past, lessees have generally obtained their mining permits without significant delay. The Partnership's lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined by lessees over the next five years. The Partnership's lessees are in the planning phase for obtaining permits for the remaining reserves planned to be mined over the next five years. However, they cannot make any assurances that they will not experience difficulty in obtaining mining permits in the future.

Timber Regulations. The Partnership's timber operations are subject to federal, state and local laws and regulations, including those related to the environment, protection of endangered species, foresting activities and health and safety. The Partnership believes it is managing its timberlands in substantial compliance with applicable federal and state regulations.

Employees

We had 104 employees at December 31, 2002, including 30 employees who directly provide services for PVR through its general partner. We consider our relations with our employees to be good.

Available Information

The Company's Internet address is www.pennvirginia.com. We make available free of charge on or through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. To date, we have inadvertently not made so available on our website any current reports on Form 8-K. We will provide, free of charge upon request, electronic or paper copies of all current reports on Form 8-K which were filed from November 15, 2002 to February 15, 2003. We will make available, free of charge, on or through our internet website, all reports on Form 8-K and amendments to those reports filed after February 15, 2003 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the Securities and Exchange Commission.

Executive Officers of the Company

The following table sets forth information concerning our executive officers. Each officer is elected annually by the Board of Directors and serves at the pleasure of the Board of Directors.

Name	*Age*	*Position with the Company*
A. James Dearlove	55	President and Chief Executive Officer
Frank A. Pici	47	Executive Vice President and Chief Financial Officer
Keith D. Horton	49	Executive Vice President
H. Baird Whitehead	52	Executive Vice President
Nancy M. Snyder	49	Senior Vice President, General Counsel and Secretary
Dana G. Wright	50	Vice President and Controller

A. James Dearlove – Mr. Dearlove has served in various capacities with the Company since 1977, including as President and Chief Executive Officer and a Director of the Company since May 1996, President and Chief Operating Officer of the Company from 1994 to May 1996, Senior Vice President of the Company form 1992 to 1994 and Vice President of the Company from 1986 to 1992. He is also Chief Executive Officer and Chairman of the Board of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. He also serves as director of the Powell River Project and the National Council of Coal Lessors.

Frank A. Pici – Mr. Pici is the Executive Vice President and Chief Financial Officer of the Company, which he joined in September 2001. Mr. Pici is also the Vice President and Chief Financial Officer and a Director of Penn Virginia Resource, GP LLC. From 1996 to August 2001, Mr. Pici was Vice President of Finance and Chief Financial Officer of Mariner Energy, Inc., an oil and gas exploration and production company. Prior to 1996, he served in various capacities with Cabot Oil & Gas Corporation, including Corporate Controller from 1994 to 1996, Director, Internal Audit from 1992 to 1994, and regional accounting manager from 1989 to 1992. From 1982 to 1989, he held financial management positions with companies in the oil and gas and coal industries.

Keith D. Horton – Mr. Horton has served in various capacities with the Company since 1981, including Executive Vice President and a Director of the Company since December 2000, Vice President – Eastern Operations of the Company from May 1996 to May 1997, President of Penn Virginia Coal Company from April 1996 to October 2001, Vice President of Penn Virginia Coal Company from March

1994 to February 1996, Vice President from January 1990 to December 1998, and Manager, Coal Operations from July 1982 to December 1989, of Penn Virginia Resources Corporation. He is also the President and Chief Operating Officer and a Director of Penn Virginia Resource, GP LLC. Additionally, Mr. Horton is Chairman of the Central Appalachian Section of the Society of Mining Engineers. He also serves as a director of the Virginia Mining Association, Powell River Project and Virginia Coal Council.

H. Baird Whitehead – Mr. Whitehead is an Executive Vice President of the Company, which he joined in January 2001. Prior to joining Penn Virginia, Mr. Whitehead served in various positions with Cabot Oil & Gas Corporation. From 1998 to 2001, he served as Senior Vice President during which time he oversaw Cabot's drilling, production, and exploration activity in the Appalachia, Rocky Mountains, Mid-Continent and the Texas and Louisiana Gulf Coast areas. From 1992 to 1998, he was Vice President and Regional Manager of Cabot's Appalachian business unit and from 1989 to 1992, he was Vice President and Regional Manager of Cabot's Anadarko business unit. From 1987 to 1989, he served as Vice President of Engineering for Cabot. From 1972 to 1987, he held various engineering and supervisory positions with Texaco, Columbia Gas Transmission, and Cabot.

Nancy M. Snyder – Ms. Snyder has served as Senior Vice President of the Company since February 2003, as Vice President since December 2000 and as General Counsel and Corporate Secretary of the Company since 1997. Ms. Snyder is also the Vice President, General Counsel and a Director of Penn Virginia Resource GP, LLC. From 1993 to 1997, Ms. Snyder was a solo practitioner representing clients generally in connection with mergers and acquisitions and general corporate matters. From 1990 to 1993, Ms. Snyder served as general counsel to Nan Duskin, Inc. and its affiliated companies, which were in the businesses of womens' retail fashion and real estate. From 1983 to 1989, Ms. Snyder was an associate at the law firm of Duane Morris, where she practiced securities, banking and general corporate law.

Dana G. Wright – Mr. Wright joined the Company in July 2002 and serves as Vice President and Controller. Prior to joining Penn Virginia, he was employed for 26 years with Atlantic Richfield Company, and most recently with its publicly traded subsidiary, Vastar Resources, Inc. During that time he held a variety of financial, accounting and treasury related positions.

The following terms have the meanings indicated below when used in this report.

Bbl –	means a standard barrel of 42 U.S. gallons liquid volume
Bcf –	means one billion cubic feet
Bcfe –	means one billion cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
Gross –	acre or well means an acre or well in which a working interest is owned
Mbbl –	means one thousand barrels
Mbf –	means one thousand board feet
Mcf –	means one thousand cubic feet
MMbf –	means one million board feet
Mmbtu -	means one million British thermal units
MMcf –	means one million cubic feet
Net –	acres or wells is determined by multiplying the gross acres or wells by the owned working interest in those gross acres or wells
NYMEX –	New York Mercantile Exchange
Present value of proved reserves –	means the present value (discounted at 10%) of estimated future cash flows from proved oil and natural gas reserves, as estimated by our independent engineers, reduced by additional estimated future operating expenses, development expenditures and abandonment costs (net of salvage value) associated therewith (before income taxes)
Probable Coal Reserves –	means those reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Proved Reserves – means those estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions

Proven Coal Reserves – means those reserves for which: (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, depth and mineral content of reserves are well-established.

Standardized Measure – means present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows

Working Interest – means a cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease

Item 2 ⇒ Properties

Facilities

We are headquartered in Radnor, Pennsylvania with additional offices in Kingsport, Tennessee, Houston, Texas and Charleston, West Virginia. We believe that our properties are adequate for our current needs.

Title to Properties

We believe that we have satisfactory title to all of our properties in accordance with standards generally accepted in the oil and natural gas and coal royalty and land management industries.

As is customary in the oil and gas industry, we make only a cursory review of title to farmout acreage and to undeveloped oil and gas leases upon execution of any contracts. Prior to the commencement of drilling operations, a thorough title examination is conducted and curative work is performed with respect to significant defects. To the extent title opinions or other investigations reflect defects, we cure such title defects. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Prior to completing an acquisition of producing oil and gas assets, we obtain title opinions on all material leases. Our oil and gas properties are subject to customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or affect the value of such properties.

Of the 615 million tons of proven and probable coal reserves to which the Partnership has rights as of December 31, 2002, PVR owned the mineral rights and the majority of related surface rights to 572 million tons, or 93 percent, and leased the remaining 43 million tons, or 7 percent, from unaffiliated third parties. In addition to the revenues the Partnership receives from its coal business, it also earns revenues from the sale of timber. At December 31, 2002, the Partnership owned 114,500 surface acres of timberland containing 168 million board feet of inventory.

Oil and Gas

Production and Pricing

The following table sets forth production, sales prices and production costs with respect to our properties for the years ended December 31, 2002, 2001 and 2000.

	2002	2001	2000
Production			
Oil and condensate (Mbbls)*	**349**	164	31
Natural gas (MMcf)*	**18,697**	13,130	11,645
Total production (MMcfe)*	**20,791**	14,114	11,831
Average sales price			
Oil and condensate ($/Bbl)	**$ 23.63**	$ 22.94	$ 26.84
Natural gas ($/Mcf)	**$ 3.35**	4.06	3.95
Production cost ($/Mcfe)			
Lease operating expense	**$ 0.45**	$ 0.40	$ 0.38
Taxes other than income	**0.27**	0.31	0.24
General and Administrative Expense	**0.40**	0.38	0.22
Total production cost	**$ 1.12**	$ 1.09	$ 0.84
Hedging Summary			
Natural gas prices ($/Mcf):			
Actual price received for production	**$ 3.39**	$ 3.92	$ 3.95
Effect of derivative hedging activities	**(0.04)**	0.14	–
Average realized price	**$ 3.35**	$ 4.06	$ 3.95
Crude oil prices ($/Bbl):			
Actual price received for production	**$ 24.39**	$ 22.45	$ 26.84
Effect of derivative hedging activities	**(0.76)**	0.49	–
Average realized price	**$ 23.63**	$ 22.94	$ 26.84

**Production for 2002 does not include approximately 16 Mbbls of oil condensate and 18 MMcf of natural gas production, or 114 MMcfe, related to discontinued operations. 2001 production volumes for properties sold were insignificant.*

Proved Reserves

We had proved reserves of 241 Bcf of natural gas and 5.4 million barrels of crude oil and condensate at December 31, 2002. The present value of the estimated future cash flows discounted at 10 percent (pre-tax SEC PV10 Value) at December 31, 2002, was $481 million. At December 31, 2002, we had 195 gross (128.3 net) proved undeveloped drilling locations.

	Oil and Condensate (MMbbls)	*Natural Gas (Bcf)*	*Natural Gas Equivalents (Bcfe)*	*Pre-tax SEC PV10 Value ($MM)*	*Year-End Weighted Average Prices Used*	
					$/Bbl	*$/Mcf*
2002						
Developed	**2.9**	**199**	**216**	**$ 404**		
Undeveloped	**2.5**	**42**	**57**	**77**		
Total	**5.4**	**241**	**273**	**$ 481**	**$ 31.13**	**$ 4.74**
2001						
Developed	2.2	183	196	$ 202		
Undeveloped	1.7	46	56	40		
Total	3.9	229	252	$ 242	$ 20.40	$ 2.65
2000						
Developed	0.1	146	147	$ 540		
Undeveloped	–	28	28	104		
Total	0.1	174	175	$ 644	$ 23.31	$ 9.91

The standardized measure of discounted future net cash flows, which represents the present value of future net revenues after income taxes discounted at ten percent, was $355 million, $189 million and $467 million at December 31, 2002, 2001 and 2000, respectively. For information on the changes in standardized measure of discounted future net cash flows. See Note 22 (Supplementary Information on Oil and Gas Producing Activities (Unaudited)) of the Notes to the Consolidated Financial Statements, for more information.

In accordance with the Securities and Exchange Commission's guidelines, the engineers' estimates of future net revenues from our properties and the pre-tax SEC PV10 value thereof are made using oil and natural gas sales prices in effect as of December 31, 2002. The prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. Net proved oil and gas reserves for the three years ended December 31, 2002 were estimated by Wright and Company, Inc. Prices for oil and gas are subject to substantial seasonal fluctuations and prices for each are subject to substantial fluctuations as a result of numerous other factors. See Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations.

Proved reserves are the estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. Therefore, the pre-tax SEC PV10 value amounts shown above should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. The information set forth in the foregoing tables includes revisions of certain volumetric reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in production prices.

Acreage

The following table sets forth our developed and undeveloped acreage at December 31, 2002. The acreage is located in the eastern and southern portions of the United States.

(in thousands)	Gross Acreage	Net Acreage
Developed	611	487
Undeveloped	246	131
Total	857	618

Wells Drilled

The following table sets forth the gross and net number of exploratory and development wells drilled during the last three years. The number of wells drilled refers to the number of wells spud at any time during the respective year. Net wells equal the number of gross wells multiplied by our working interest in each of the gross wells. Productive wells represent either wells which were producing or which were capable of commercial production.

	2002		2001		2000	
Development	**Gross**	**Net**	Gross	Net	Gross	Net
Productive	**87**	**58.4**	125	96.1	99	75.3
Non-productive	**3**	**2.5**	5	5.0	1	0.9
	90	**60.9**	130	101.1	100	76.2
Exploratory						
Productive	**3**	**3.0**	19	14.5	1	0.2
Non-productive	**3**	**1.6**	5	3.5	5	1.3
Under evaluation	**–**	**–**	–	–	3	1.4
	6	**4.6**	24	18.0	9	2.9
Total	**96**	**65.5**	154	119.1	109	79.1

Productive Wells

The number of productive oil and gas wells in which we had a working interest at December 31, 2002 is set forth below. Productive wells are producing wells or wells capable of commercial production.

Operated Wells		*Non-Operated Wells*		*Total*	
Gross	Net	Gross	Net	Gross	Net
692	668	430	63	1,122	731

In addition to the above working interest wells, Penn Virginia owns royalty interests in 2,346 gross wells.

Coal Royalty and Land Management

The Partnership's coal reserves at December 31, 2002 covered 241,000 acres, including fee and leased acreage, in Virginia, West Virginia, New Mexico and eastern Kentucky. The coal reserves are in various surface and underground seams.

The Partnership's proven and probable coal reserves are estimated at 615 million tons as of December 31, 2002. Reserves are coal tons that can be economically extracted or produced at the time of determination considering legal, economic and technical limitations. Proven coal reserves are reserves for which (a) the quantity is computed from dimensions revealed in outcrops, trenches, working or drill holes; grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, and depth and mineral content of reserves are well-established. Probable coal reserves are reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

In areas where geologic conditions indicate potential inconsistencies related to coal reserves, the Partnership performs additional drilling to ensure the continuity and mineablility of coal reserves. Consequently, sampling in those areas involves drill holes that are spaced closer together than those distances cited above.

Reserve estimates are adjusted annually for production, unmineable areas, acquisitions and sales of coal in place. The majority of PVR's reserves are high in energy content, low in sulfur and suitable for either steam or metallurgical markets.

The amount of coal a lessee can profitably mine at any given time is subject to several factors and may be substantially different from "proven and probable reserves." Included among the factors that influence profitability are the existing market price, coal quality and operating costs.

The Partnership's timber assets consist of various hardwoods, primarily red oak, white oak, yellow poplar and black cherry. At December 31, 2002, the Partnership owned an estimated 168 MMbf of standing saw timber.

Item 3 ⇒ Legal Proceedings

We are involved in various legal proceedings arising in the ordinary course of business. While the ultimate results of these cannot be predicted with certainty, management believes these claims will not have a material effect on our financial position, liquidity or operations.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2002.

PART II

Item 5 Market for the Company's Common Stock and Related Stockholder Matters

Common Stock Market Prices And Dividends

High and low closing stock prices and dividends for the last two years were:

	2002			2001		
	Sales Price			*Sales Price*		
	High	***Low***	***Cash Dividends Paid***	*High*	*Low*	*Cash Dividends Paid*
Quarter Ended:						
March 31	**$ 40.15**	**$ 26.84**	**$ 0.225**	$ 37.39	$ 30.00	$ 0.225
June 30	**$ 41.87**	**$ 32.58**	**$ 0.225**	$ 45.10	$ 31.10	$ 0.225
September 30	**$ 38.98**	**$ 30.30**	**$ 0.225**	$ 38.41	$ 27.15	$ 0.225
December 31	**$ 36.90**	**$ 30.35**	**$ 0.225**	$ 38.50	$ 27.90	$ 0.225

The Company's common stock is traded on the New York Stock Exchange under the symbol PVA.

Item 6 Selected Financial Data

Five Year Selected Financial Data

			Year Ended December 31,		
(in thousands except share data)	**2002**	2001	2000	1999	1998
Revenues	**$ 110,957**	$ 96,571	$ 105,998	$ 47,697	$ 38,324
Operating income[(a,b)]	**$ 30,791**	$ 1,563	$ 65,684	$ 20,715	$ 10,273
Net income[(c)]	**$ 12,104**	$ 34,337	$ 39,265	$ 14,504	$ 9,591
Per common share:					
Net income, basic	**$ 1.35**	$ 3.92	$ 4.76	$ 1.73	$ 1.15
Net income, diluted	**$ 1.34**	$ 3.86	$ 4.69	$ 1.71	$ 1.13
Dividends paid	**$ 0.90**	$ 0.90	$ 0.90	$ 0.90	$ 0.90
Weighted average shares outstanding, basic	**8,930**	8,770	8,241	8,406	8,310
Weighted average shares outstanding, diluted	**8,974**	8,896	8,371	8,480	8,463
Total assets[(d)]	**$ 586,292**	$ 457,102	$ 268,766	$ 274,011	$ 256,931
Long-term debt[(e)]	**$ 106,887**	$ 46,887	$ 47,500	$ 78,475	$ 37,967
Minority interest in PVR	**$ 192,770**	$ 144,039	$ –	$ –	$ –
Shareholders' equity	**$ 187,956**	$ 185,454	$ 171,162	$ 154,343	$ 170,259

(a) Certain reclassifications have been made to conform to the current year presentation.

(b) Operating income in 2002 includes a $0.8 million impairment on oil and gas properties. Operating income in 2001 included a $33.6 million impairment on oil and gas properties. Operating income in 2000 included a $23.9 million gain on the sale of certain oil and gas properties.

(c) Net income in 2001 included a $54.7 million ($35.6 million after tax) gain on the sale of Norfolk Southern Corporation common stock.

(d) Total assets reflect the acquisition of coal reserves from Peabody in December 2002 for $130.5 million. Total assets in 2001 include the Gulf Coast oil and gas properties of $157.1 million that were purchased in July 2001.

(e) Long-term debt in 2002 includes PVA outstanding borrowing of $16 million on its revolving credit facility. Also included is PVR outstanding borrowings of $90.9 million consisting of $47.5 million borrowed against its $50 million revolving credit facility and $43.3 million of a fully-drawn term loan. Long-term debt in 2001 included $43.4 of long-term debt of PVR that was secured by $43.4 million of U.S. Treasuries also held by PVR.

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

The following review of operations and financial condition of Penn Virginia Corporation and subsidiaries should be read in conjunction with the Consolidated Financial Statements and Notes thereto.

Overview

Penn Virginia Corporation ("Penn Virginia" or the "Company") is an independent energy company that is engaged in two primary business segments. Our oil and gas segment explores for, develops and produces crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal royalty and land management segment operates through our ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a Delaware limited partnership, see Note 2 (Penn Virginia Resource Partners, L.P.) of the Notes to the Consolidated Financial Statements.

We are committed to increasing value to our shareholders by conducting a balanced program of investment in our two business segments. In the oil and gas segment, we intend to execute a program combining relatively low risk, moderate return development drilling in the east with higher risk, higher return exploration and development drilling in the onshore Gulf Coast, supplemented periodically with acquisitions. In addition to our continuing development program, we are expanding our eastern presence by developing coalbed methane gas reserves in Appalachia. By employing horizontal drilling techniques, we expect to increase production rates from coalbed methane reserves we own. We are also committed to expanding our onshore Gulf Coast reserves and production internally through our drilling program and by acquiring reserves with favorable return potential.

In 2002, these efforts resulted in a 47 percent increase in oil and gas production from 2001, and we expect an increase in 2003 oil and gas production of at least 30 percent, with a corresponding increase in operating cash flow. In January 2003, we completed an acquisition of approximately 31.8 Bcfe of proved reserves in the South Texas area of the onshore Gulf Coast region for $32.5 million, which will provide a significant part of the expected growth in 2003 production.

Our oil and gas capital expenditures for 2003, including the January 2003 South Texas acquisition, are expected to be $110 to $120 million. Borrowings against our $140 million credit facility were $16 million as of December 31, 2002, and we expect to fund our 2003 capital expenditures with a combination of internal cash flow and credit facility borrowings.

During 2002, PVR completed its first two coal reserve acquisitions since its initial public offering in October 2001. In December 2002, PVR announced the formation of a strategic alliance with Peabody, resulting from the purchase from and leaseback to Peabody of approximately 120 million tons of coal reserves in New Mexico and northern West Virginia for $72.5 million in cash and a total of 2.76 million common units and Class B common units. The Peabody Acquisition significantly expanded PVR's geographic diversity and included incentives for Peabody to source additional assets to the Partnership in the future. In August 2002, PVR also purchased approximately 16 million tons of coal reserves in northern West Virginia for $12.0 million. The two acquisitions are expected to contribute 12.3 million to 12.9 million tons of production and $16.5 million to $17.5 million of cash flow from operations to PVR in 2003.

Coal-related capital expenditures in 2003 are expected to be $3.0 to $3.3 million for the construction of new coal service-related projects for which PVR will collect a fee. As of December 31, 2002, PVR had borrowed $90.9 million against its credit facility, and it is currently attempting to refinance those borrowings with a more permanent form of debt. The Partnership expects to complete the refinancing during the first quarter of 2003. Cash flow from operations, supplemented with credit facility borrowings, are expected to be adequate for PVR to fund 2003 capital expenditures and distributions to unitholders.

Critical Accounting Policies and Estimates

Oil and Gas Properties. We use the successful efforts method of accounting for our oil and gas operations. Under this method of accounting, costs to acquire mineral interests in oil and gas properties and to drill and equip development wells (including development dry holes) are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, and later charged to expense upon determination that the well does not justify commercial development. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred.

The costs of unproved leaseholds are capitalized pending the results of exploration efforts. Unproved leasehold costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, the cost of the property has been impaired. As unproved leaseholds are determined to be productive, the related costs are transferred to proved leaseholds. As of December 31, 2002, we had approximately $57.6 million of unproved leasehold costs included in oil and gas properties on our consolidated balance sheet. We expect to complete an evaluation of our unproved leaseholds over the next two to three years.

Other Property and Equipment. Other property and equipment is carried at cost and includes expenditures for additions and improvements, which substantially increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Depreciation of property and equipment is generally computed using the straight-line method over their estimated useful lives, varying from 3 years to 20 years. Coal properties are depleted on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. When an asset is retired or sold, its cost and related accumulated depreciation are removed from the accounts. The difference between undepreciated cost and proceeds from disposition is recorded as a gain or loss.

Impairment of Long-Lived Assets. We review our long-lived assets to be held and used, including proved oil and gas properties and the Partnership's coal properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss must be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we would recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the expected present value of future net cash flows from proved reserves, discounted utilizing a risk-free interest rate commensurate with the remaining lives for the respective oil and gas properties.

Oil and Gas Revenues. Oil and gas sales revenues are recognized when crude oil and natural gas volumes are produced and sold for our account. Each working interest owner in a well generally has the right to a specific percentage of production, and often actual production sold for any particular owner will differ from such owner's ownership percentage. When, under contract terms, these differences are settled in cash, revenues are adjusted accordingly.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenue from those sales. Coal leases other than those with Peabody affiliates are based on minimum monthly or annual payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price. Peabody leases are leased on fixed royalties which escalate annually and also provide for minimum monthly payments.

Coal Services. Coal services revenues are recognized when lessees use the Partnership's facilities for the processing and transportation of coal. Coal services revenues consist of fees collected from the Partnership's lessees for the use of the Partnership's loadout facility, coal preparation plant, dock loading facility.

Timber. Timber revenues are recognized as timber is sold on a contract basis where independent contractors harvest and sell the timber and, from time to time, in a competitive bid process involving sales of standing timber on individual parcels. Title and risk of loss pass to the independent contractors upon the execution of the contract. In addition, if the contractors do not harvest the timber within the specified time period, the title of the timber reverts back to the Partnership with no refund of original payment.

Minimum Rentals. Most of the Partnership's lessees must make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalty revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods (the recoupment period), the deferred income attributable to the minimum payment is recognized as minimum rental revenues. Revenues associated with minimum rentals are included in other revenues.

Price Risk Management Activities. From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas and crude oil price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of costless collars and swaps. All derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we are utilizing only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. All hedge transactions are subject to our risk management policy, which has been reviewed and approved by the Board of Directors. We formally document all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. We measure hedge effectiveness on a period basis. When it is determined that a derivative is not highly effective as a hedge, or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively. When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively. Gains and losses on hedging instruments when settled are included in natural gas or crude oil production revenues in the period that the related production is delivered. The fair values of our hedging instruments are determined based on third party forward price quotes for NYMEX Henry Hub and West Texas Intermediate closing prices.

Reserves. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, projecting future production rates and projecting the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods.

Results of Operations

Selected Financial Data – Consolidated

(in millions, except share data)	**2002**	2001	2000
Revenues	**$ 111.0**	$ 96.6	$ 106.0
Operating costs and expenses	**80.2**	95.0	40.3
Operating income	**30.8**	1.6	65.7
Net income	**12.1**	34.3	39.3
Net income per share, basic	**1.35**	3.92	4.76
Net income per share, diluted	**1.34**	3.86	4.69
Cash flows provided by operating activities	**65.8**	44.2	41.7

Consolidated Net Income

Our 2002 net income was $12.1 million, compared with $34.3 million in 2001 and $39.3 million in 2000. Revenues for 2002 were $111.0 million, compared with $96.6 million and $106.0 million in 2001 and 2000, respectively.

The 2001 results included a pre-tax gain on the sale of securities of approximately $54.7 million ($35.5 million after tax). Also included in the 2001 results was the impairment of certain oil and gas properties, for which we recorded a $33.6 million ($21.8 million after tax) impairment charge. In addition to the gain on sale of securities, net of the impairment charge noted above, the decrease in 2002 net income from 2001 was primarily due to lower natural gas prices and the minority interest resulting from the ownership change of our coal reserves in connection with the initial public offering of the Partnership's common units in the fourth quarter of 2001.

In 2000, we recorded a pre-tax gain of $23.9 million ($15.5 million after tax) on the sale of non-strategic natural gas properties located in Kentucky and West Virginia. The decrease in 2001 net income from 2000 was primarily due to increased exploration, operating and general and administrative expenses as a result of the acquisition of Gulf Coast properties in 2001.

Corporate and Other

Dividends. In April 2001, we sold 3.3 million shares of common stock of Norfolk Southern Corporation at an average selling price of $17.39 per share. Proceeds, net of commissions, totaled approximately $57.4 million. As a result, dividend income decreased from $2.6 million in 2000 to $0.2 million in 2001. No dividends were received during 2002.

Oil and Gas Segment

In our oil and gas segment, we explore for, develop and produce crude oil and natural gas in the eastern and Gulf Coast onshore regions of the United States.

We use the successful efforts method of accounting for our oil and gas operations. Under this method of accounting, costs to acquire mineral interests in oil and gas properties and to drill and equip development wells (including development dry holes) are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, and later charged to expense upon determination that the well does not justify commercial development. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred.

The costs of unproved leaseholds are capitalized pending the results of exploration efforts. Unproved leasehold costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, the cost of the property has been impaired. As unproved leaseholds are determined to be productive, the related costs are transferred to proved leaseholds.

Oil and natural gas revenues are generally recorded using the entitlement method in which we recognize our ownership interest in the production as revenue. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold may differ from an ownership percentage. Using entitlement accounting, a receivable is recorded when sales are less than our entitlement and deferred revenue is recognized when sales are greater than our entitlement.

We review our long-lived assets, including proved oil and natural gas properties, for possible impairment whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss must be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we would recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated using the expected present value of future net cash flows from proved reserves, utilizing a risk-free interest rate.

Our revenues, profitability and future rate of growth are highly dependent on the prevailing prices for oil and natural gas, which are affected by numerous factors that are generally beyond the Company's control. Crude oil prices are generally determined by global supply and demand. Natural gas prices are influenced by national and regional supply and demand. A substantial or extended decline in the prices of oil or natural gas could have a material adverse effect on our revenues, profitability and cash flow and could, under certain circumstances, result in an impairment of our oil and natural gas properties.

Our future profitability and growth is also highly dependent on the results of our exploratory and development drilling programs.

Selected Financial and Operating Data – Oil and Gas

(in thousands, except share data)	2002	2001	2000
Revenues			
Oil and condensate	**$ 8,246**	$ 3,762	$ 832
Natural gas	**62,552**	53,263	46,019
Other	**714**	753	24,554
Total Revenues	**$ 71,512**	$ 57,778	$ 71,405
Expenses			
Lease operating	**9,253**	5,631	4,562
Exploration	**7,549**	11,514	5,080
Taxes other than income	**5,618**	4,439	2,809
General and administrative	**8,381**	5,330	2,656
Operating expenses before non-cash charges	**30,801**	26,914	15,107
Depreciation, depletion and amortization	**26,336**	16,418	9,883
Impairment of properties	**796**	33,583	–
Total Operating Expenses	**57,933**	76,915	24,990
Operating Income (Loss)	**$ 13,579**	$ (19,137)	$ 46,415
Production			
Oil and condensate (Mbbls)*	**349**	164	31
Natural gas (MMcf)*	**18,697**	13,130	11,645
Total production (MMcfe)*	**20,791**	14,114	11,831
Realized Prices			
Oil and condensate ($/Bbl)	**$ 23.63**	$ 22.94	$ 26.84
Natural gas ($/Mcf)	**3.35**	4.06	3.95
Production cost ($/Mcfe)			
Lease operating expense	**$ 0.45**	$ 0.40	$ 0.38
Taxes other than income	**0.27**	0.31	0.24
General and administrative expense	**0.40**	0.38	0.22
Total production cost	**$ 1.12**	$ 1.09	$ 0.84
Hedging Summary			
Natural gas prices ($/Mcf):			
Actual price received for production	**$ 3.39**	$ 3.92	3.95
Effect of hedging activities	**(0.04)**	0.14	–
Average realized price	**$ 3.35**	$ 4.06	$ 3.95
Crude oil prices ($/Bbl):			
Actual price received for production	**$ 24.39**	$ 22.45	$ 26.84
Effect of hedging activities	**(0.76)**	0.49	–
Average realized price	**$ 23.63**	$ 22.94	$ 26.84

**Production for 2002 does not include 16 Mbbls of oil and condensate and 18 MMcf of natural gas production, or 114 MMcfe, related to discontinued operations. 2001 production volumes for properties sold were insignificant.*

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

Revenues. Oil and gas revenues increased $13.7 million to $71.5 million in 2002 from 2001 primarily due to an increase in crude oil and natural gas production.

Crude oil and natural gas production increased to 20.8 Bcfe in 2002, a 47 percent increase over 2001. The increase was primarily due to the inclusion of a full year of production from the Gulf Coast oil and gas properties acquired in July 2001 and development drilling success in connection with our Gulf Coast, Mississippi and Appalachian assets. Approximately 90 percent of our 2002 production was natural gas.

The average natural gas price received during 2002 was $3.35 per Mcf compared with $4.06 per Mcf in 2001, a 17 percent decrease. The average oil price received was $23.63 per barrel for 2002, up three percent from $22.94 per barrel in 2001.

Due to the volatility of crude oil and natural gas prices, we sometimes hedge the price received for sales volumes through the use of swaps and costless collars. Gains and losses from hedging activities are included in revenues when the hedged production occurs. We recognized a loss on settled hedging activities of $1.0 million in 2002 and a gain of $1.9 million in 2001.

Operating expenses. Production costs increased from $5.6 million in 2001 to $9.3 million in 2002. The increase was primarily attributable to the full year impact of operating costs related to our acquisition of certain Gulf Coast oil and gas properties in late July of 2001.

Exploration expenses decreased from $11.5 million in 2001 to $7.5 million in 2002 due to lower exploratory dry hole costs incurred this year. Seismic expenditures were $4.7 million in 2002, up from $2.2 million in 2001. The impact of these higher costs was offset by reduced write-offs of unproved property in 2002.

Taxes other than income taxes increased by $1.2 million to $5.6 million in 2002. The increased taxes were a result of the higher production and revenue levels in 2002.

General and administrative ("G&A") expenses increased to $8.4 million in 2002 from $5.3 million in 2001. The increase was primarily attributable to our acquisition of the Gulf Coast oil and gas properties in July 2001 and related personnel expenses.

Oil and gas depreciation, depletion and amortization ("DD&A") increased to $26.3 million in 2002 from $16.4 million in 2001. This increase was primarily due to increased production related to the Gulf Coast assets acquired in July 2001, as well as increased DD&A rates due to changes in reserve estimates and capital additions.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues. Oil and gas revenues increased $10.2 million to $57.0 million in 2001 from 2000 primarily due to an increase in crude oil and natural gas production.

Crude oil and natural gas sales combined increased 22 percent to $57.0 million due to a 19 percent increase in production. The increase was primarily due to production related to our acquisition of certain Gulf Coast oil and gas properties in July 2001 and to increased production from the Gwinville Field, offset in part by production lost from properties disposed of in the fourth quarter of 2000. Approximately 93 percent of our 2001 production was natural gas. The average natural gas price received during 2001 was $4.06 per Mcf compared with $3.95 per Mcf in 2000, a three percent increase. The average oil price received was $22.94 per barrel for 2001, down 15 percent from $26.84 per barrel in 2000. We recognized a gain of $1.9 million in 2001 on hedging activities with no gain or loss recognized in 2000.

Operating expenses. Production costs, consisting of lease operating expense and taxes other than income, increased from $7.4 million in 2000 to $10.0 million in 2001. Production costs increased from $0.62 per Mcfe in 2000 to $0.71 per Mcfe in 2001. The increase was primarily attributable to the acquisition of certain Gulf Coast oil and gas properties in July 2001.

Exploration expenses increased from $5.1 million in 2000 to $11.5 million in 2001. The $11.5 million in 2001 consisted of $2.4 million in seismic expenditures, charges relating to five gross (3.5 net) nonproductive exploratory wells and the impairment of unproved leasehold costs. Our increased seismic expenditures for the year, compared with 1.7 million in 2000, represented a continued effort to establish a balanced exploratory program.

G&A expenses increased to $5.3 million in 2001 from $2.7 million in 2000. The increase was attributable to the acquisition of certain Gulf Coast oil and gas properties in late July of 2001and related personnel expenses.

Oil and gas DD&A increased to $16.4 million in 2000 from $9.9 million in 2000. This increase was primarily due to increased production and a higher cost basis in the producing assets. The acquisition of certain Gulf Coast oil and gas properties in July 2001 was completed when crude oil and natural gas future prices were higher than forecasted prices at year-end 2001. As a result of low commodity prices in the fourth quarter 2001, we subjected all properties to impairment testing and recognized a pretax impairment charge related primarily to our Texas properties of $33.6 million ($21.8 million after tax).

Coal Royalty and Land Management Segment

The coal royalty and land management segment includes PVR's mineral rights to coal reserves, its timber assets and its other land assets. The assets, liabilities and earnings of PVR are fully consolidated in our financial statements, with the public unitholders' interest reflected as a minority interest.

The Partnership enters into leases with various third-party operators for the right to mine coal reserves on the Partnership's properties in exchange for royalty payments. Coal royalty revenues under non-Peabody leases are based on the higher of a percentage of the gross sales price or a fixed price per ton of coal sold, with pre-established minimum monthly or annual payments. Under the Peabody leases, coal royalty revenues are based on fixed royalty rates which escalate annually, also with pre-established monthly minimums. In addition to coal royalty revenues, the Partnership generates coal service revenues from fees charged to lessees for the use of coal preparation and transportation facilities. The Partnership also generates revenues from the sale of timber on its properties.

The coal royalty stream is impacted by several factors, which PVR generally cannot control. The number of tons mined annually is determined by an operator's mining efficiency, labor availability, geologic conditions, access to capital, ability to market coal and ability to arrange reliable transportation to the end-user. The possibility exists that new legislation or regulations may be adopted which may have a significant impact on the mining operations of the Partnership's lessees or their customers' ability to use coal and may require PVR, its lessees or its lessee's customers to change operations significantly or incur substantial costs.

Selected Financial and Operating Data – Coal Royalty and Land Management

(in thousands, except as noted)	2002	2001	2000
Revenues			
Coal royalties	**$ 31,358**	$ 32,365	$ 24,308
Timber	**1,640**	1,732	2,388
Coal services	**1,704**	1,660	1,385
Other	**3,906**	1,756	2,108
Total Revenues	**38,608**	37,513	30,189
Expenses			
Operating	**3,807**	3,812	3,480
General and administrative	**6,419**	5,459	4,847
Operating expenses before non-cash charges	**10,226**	9,271	8,327
Depreciation, depletion and amortization	**3,955**	3,084	2,047
Total Operating Expenses	**14,181**	12,355	10,374
Operating Income	**$ 24,427**	$ 25,158	$ 19,815
Production			
Royalty coal tons produced by lessees (thousands)	**14,281**	15,306	12,536
Timber sales (Mbf)	**8,345**	8,741	8,545
Prices			
Royalty per ton	**$ 2.20**	$ 2.11	$ 1.94
Timber sales price per Mbf	**$ 187**	$ 168	$ 257

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

Revenues. Coal royalty and land management segment revenues for the year ended December 31, 2002 were $38.6 million compared to $37.5 million for the year ended December 31, 2001, an increase of $1.1 million, or three percent.

Coal royalty revenues for the year ended December 31, 2002 were $31.4 million compared to $32.4 million for the year ended December 31, 2001, a decrease of $1.0 million, or three percent. Over these same periods, production decreased by 1.0 million tons, or seven percent, from 15.3 million tons to 14.3 millions tons. These decreases were primarily due to weaker coal demand in 2002 in general, and more specifically, the idling of production at the Fork Creek property caused by the lessee's bankruptcy.

Timber revenues decreased to $1.6 million for the year ended December 31, 2002 from $1.7 million for the year ended December 31, 2001, a decrease of $0.1 million, or five percent. Volume sold declined 396 thousand board feet (Mbf), or five percent, to 8,345 Mbf in 2002, compared to 8,741 Mbf for 2001.

Coal services revenues remained constant at $1.7 million for the years ended December 31, 2002 and 2001. Slight increases in revenues generated from PVR's modular preparation plants and dock loadout facility were offset by a minor reduction in revenues from its unit-train loadout facility.

Other revenues were $3.9 million for the year ended December 31, 2002 compared to $1.8 million for the year ended December 31, 2001, an increase of $2.1 million, or 122 percent. The increase was primarily due to the recognition of minimum rental payments received from the Partnership's lessees which are no longer recoupable by the lessee. Two of PVR's lessees, Horizon Resources, Inc. (formerly AEI Resources, Inc.) and Pen Holdings, Inc., both of which filed Chapter 11 bankruptcies during 2002, accounted for $1.9 million of minimum rental income in 2002.

Operating expenses. Operating expenses, which include both lease operating expenses and taxes other than income, were $3.8 million for the years ended December 31, 2002 and 2001. Lease operating expenses were $2.9 million for the year ended December 31, 2002 compared to $3.2 million for the year ended December 31, 2001, a decrease of $0.3 million, or nine percent. This decrease is primarily due to a decrease in production by lessees on the Partnership's subleased properties, offset by temporary mine maintenance costs on its Coal River property. Aggregate production from subleased properties decreased to 1.8 million tons for the year ended December 31, 2002 from 2.3 million tons for the year ended December 31, 2001. Taxes other than income for the year ended December 31, 2002 was $0.9 million compared to $0.6 million for the year ended December 31, 2001, an increase of $0.3 million, or 45 percent. The increase was primarily due to an increase in state franchise taxes resulting from the Partnership's change from a corporate to a partnership structure in late 2001. Prior to the initial formation of the Partnership, franchise taxes were calculated based on filing as a corporation.

G&A expenses increased to $6.4 million for the year ended December 31, 2002 compared to $5.5 million for the year ended December 31, 2001, representing an 18 percent increase. The increase was primarily attributable to a full year of fees and expenses associated with the Partnership being a publicly traded entity.

Depreciation and depletion expense for the year ended December 31, 2002 was $4.0 million compared to $3.1 million for the year ended December 31, 2001, an increase of $0.9 million, or 28 percent. The increase in depreciation, depletion and amortization resulted from an increase in the depletive write-off rate per ton caused by a downward revision of coal reserves in the late 2001, higher cost coal properties being added to the depletable base as a result of recent acquisitions, and additional depreciation related to coal services capital projects.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Revenues. Coal royalty and land management segment revenues were $37.5 million in 2001 and $30.2 million in 2000, representing a 24 percent increase.

Coal royalty revenues increased $8.1 million from $24.3 million in 2000 to $32.4 million in 2001. Production increases were the primary factor related to the increase in revenues. Royalty tons increased 2.8 million from 12.5 million in 2000 to 15.3 million in 2001, or 22 percent. These production increases were attributable to the start up of five new mines, the June 2001 acquisition of new properties and the completion of a capital project on another lease.

Timber revenues decreased to $1.7 million for the year ended December 31, 2001 from $2.4 million for the year ended December 31, 2000, a decrease of $0.7 million, or 27 percent. The decrease is primarily attributable to a decrease in the average price received for the timber from $257 per Mbf for the year ended December 31, 2000 to $168 per Mbf for the year ended December 31, 2001. The decrease reflects overall market conditions as well as the sale of lower priced species and lower quality timber.

Coal services revenues increased to $1.7 million for the year ended December 31, 2001 from $1.4 million in 2000, an increase of $0.3 million, or 20 percent. The increase is a direct result of the addition of a small preparation plant put into service during 2001 and additional usage of the Partnership's existing coal service facilities.

Other revenues were $1.8 million for the year ended December 31, 2001 compared with $2.1 million for the year ended December 31, 2000, a decrease of $0.3 million, or 17 percent. The decrease was primarily due to gains from the sale of property and equipment in 2000, offset by the recognition of minimum rental payments received from lessees which are no longer recoupable.

Operating expenses. Operating expenses were $3.8 million for the year ended December 31, 2001 compared with $3.5 million for the year ended December 31, 2000, an increase of $0.3 million, or 10 percent. This variance is primarily due to an increase in production by lessees on PVR's subleased properties resulting in royalty expense incurred. Production from subleased properties increased from 2.1 million tons for the year ended December 31, 2000 to 2.3 million tons for the year ended December 31, 2001, an increase of 0.2 million tons, or 10 percent.

G&A expenses increased to $5.5 million for the year ended December 31, 2001 compared to $4.8 million for the year ended December 31, 2000. This increase is primarily attributable to fees associated with tax preparation and public reporting by the Partnership.

Depreciation and depletion expense for the year ended December 31, 2001 was $3.1 million compared with $2.0 million for the year ended December 31, 2000, an increase of $1.1 million, or 51 percent. This increase primarily resulted from coal production increases of 22 percent. Depreciation and depletion expense increased, on a per ton basis, to $0.20 per ton for the year ended December 31, 2001 from $0.16 for the year ended December 31, 2000. The $0.04 increase on a per ton basis results from increased production from the Coal River property, which has a significantly higher cost basis.

Reserves

Oil and Gas Reserves

Our total proved reserves at December 31, 2002 were 273.4 Bcfe, compared with 252.8 Bcfe at December 31, 2001. At December 31, 2002, proved developed reserves comprised 79 percent of our total proved reserves, compared with 78 percent at December 31, 2001. We have 128 net proved undeveloped drilling locations at December 31, 2002, compared with 93 locations at December 31, 2001.

	2002	2001	2000
Proved reserves			
Crude oil (Mbbls)	**5,361**	3,920	71
Natural gas (MMcf)	**241,255**	229,253	174,247
Proved developed reserves			
Crude oil (Mbbls)	**2,943**	2,212	71
Natural gas (MMcf)	**198,733**	183,134	145,930
Finding and development cost[a], ($/Mcfe)			
Current year	**$ 1.34**	$ 3.26	$ 0.82
Three year weighted average	**1.81**	2.66	1.56
Reserve replacement cost[b], ($/Mcfe)			
Current year	**$ 1.32**	$ 2.22	$ 0.92
Three year weighted average	**1.60**	1.70	1.08
Reserve replacement percentage[c], ($/Mcfe)			
Current year	**206%**	660%	556%
Three year weighted average	**432%**	544%	332%

Finding and development cost, reserve replacement cost and reserve replacement percentage are not measures presented in accordance with generally accepted accounting principles ("GAAP") and are not intended to be used in lieu of GAAP presentation. These measures are commonly used within the industry as a measurement to determine the performance of a company's oil and gas activities.

(a) Finding and development cost is calculated by dividing 1) costs incurred in certain oil and gas activities less proved property acquisitions, by 2) reserve extensions, discoveries and other additions and revisions. The 2001 finding and development costs used in this calculation included $62.2 million for unproved property acquisition costs (including the impact of deferred income taxes) related to the purchase of certain Gulf Coast oil and gas properties in the third quarter of 2001. No proved reserves were recorded relative to these unproved property acquisition costs, for which future exploration and development activities will be conducted. Had the unproved property acquisition costs been excluded from the 2001 finding and development cost calculations, 2001 and three year weighted average cost per Mcfe would have been $1.41 and $1.24, respectively.

(b) Reserve replacement cost is calculated by dividing 1) costs incurred in certain oil and gas activities, including acquisitions, by 2) reserve purchases, extensions, discoveries and other additions and revisions. The 2001 reserve replacement costs used in this calculation included $62.2 million for unproved property acquisition costs described in footnote (a) above and $27.2 million of deferred income taxes on proved property acquisition costs related to the purchase of certain Gulf Coast oil and gas properties in the third quarter of 2001. Had the unproved property acquisition costs and the deferred income taxes on the proved property acquisition costs been excluded from the 2001 reserve replacement cost calculations, 2001 and three year weighted average cost per Mcfe would have been $1.26 and $1.09, respectively.

(c) Reserve replacement percentage is calculated by dividing 1) reserve purchases, revisions, extensions, discoveries and other additions, by 2) oil and gas production.

Proven and Probable Coal Reserves

The Partnership's proven and probable coal reserves were 615 million tons at December 31, 2002 compared with 493 million tons at December 31, 2001. Royalties were collected for 14.3 million tons mined on the Partnership's properties in 2002.

Capital Resources and Liquidity

Prior to 2001, the Company satisfied its working capital requirements and funded its capital expenditure and dividend payments with cash generated from operations and credit facility borrowings. In 2001, the acquisition of Gulf Coast properties was funded with credit facility borrowings that were subsequently repaid with proceeds from PVR's initial public offering. Although results are consolidated for financial reporting, the resultant change in ownership structure of PVR caused the Company and PVR to operate with independent capital structures. The Company and PVR have separate credit facilities, for which neither entity guarantees the debt of the other. Since PVR's public offering, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and, in the case of PVR's Peabody Acquisition, issuance of new partnership units. We expect that the cash needs of the Company and PVR will continue to be met with a combination of these funding sources.

Except where noted, the following discussion of cash flows and contractual obligations relates to consolidated results of the Company and PVR.

Cash flows from Operating Activities

Net cash provided from operating activities was $65.8 million in 2002, compared with $44.2 million in 2001 and $41.7 million in 2000. Our consolidated cash balance increased to $13.3 million in 2002 compared with $9.6 million in 2001 and $0.7 million in 2000, respectively. As a result of PVR's public offering, approximately $9.6 million and $8.3 million of the consolidated cash balance as of December 31, 2002 and 2001, respectively, was held by PVR primarily for working capital requirements.

Cash flows from Investing Activities

Cash used in investing activities was $99.5 million in 2002, compared with $179.4 million in 2001 and $3.3 million in 2000. Cash was used during these periods primarily for capital expenditures for oil and gas development and exploration activities and acquisitions of oil and gas and coal properties, offset in part by proceeds from sales of securities and non-strategic oil and gas properties.

Capital expenditures totaled $204.8 million in 2002, compared with $241.7 million in 2001 and $61.4 million in 2000. The following table sets forth capital expenditures, made during the periods indicated.

	Year ended December 31,		
(in thousands)	**2002**	2001	2000
Oil and gas			
Development Drilling	**$ 39,014**	$ 30,123	$ 18,317
Exploration Drilling	**2,485**	11,253	3,200
Seismic and other	**5,358**	2,561	1,925
Lease Acquisitions	**7,346**	161,631	36,916
Field Projects	**2,736**	1,422	244
Total	**56,939**	206,990	60,602
Coal royalty and land management			
Lease acquisitions	**138,450**	32,992	–
Support equipment and facilities	**9,085**	677	485
Total	**147,535**	33,669	485
Other	**343**	1,074	281
Total capital expenditures	**$ 204,817**	$ 241,733	$ 61,368

The capital expenditures noted above include noncash items related to equity issued in the form of PVR common units in connection with PVR's Peabody Acquisition in 2002 and deferred taxes related to the Company's acquisition of Gulf Coast properties in 2001.

Management is committed to expanding its oil and natural gas operations over the next several years through a combination of exploitation, exploration and acquisition of new properties. We have a portfolio of assets which balance relatively low risk, moderate return development projects in Appalachia, Mississippi and west Texas with relatively moderate risk, potentially higher return development projects and exploration prospects in south Texas and south Louisiana.

Oil and gas segment capital expenditures for 2003, including our January 2003 acquisition of properties in South Texas for $32.5 million, are estimated to be $110 to $120 million. Approximately $53 to $57 million of the planned oil and gas capital expenditures are expected to be for development drilling projects, including horizontal coalbed methane drilling in Appalachia, development of the South Texas properties acquired in January 2003 and continued drilling in our Mississippi and west Texas fields. Exploration drilling is expected to be approximately $11 to $13 million of the planned expenditures, concentrated primarily in south Louisiana and south Texas. Expenditures to build our library of 3-D seismic data for drilling prospect generation is expected to be approximately $6 to $7 million, and lease acquisition and field project expenditures are expected to be $8 to $10 million. Capital expenditures for 2003 in the coal royalty and land management segment are expected to be up to $3 million for the construction of fee-based infrastructure facilities. We continually review drilling and other capital expenditure plans and may change these amounts based on industry conditions and the availability of capital. We believe our cash flow from operations and sources of debt financing are sufficient to fund our 2003 planned capital expenditure program.

Cash flows from Financing Activities

Net cash provided by (used in) financing activities was $37.4 million in 2002, compared with $144.1 million in 2001 and ($38.4) million in 2000. Credit facility borrowings provided approximately $58.8 million of cash from financing activities during 2002, offset in part by $8.0 million of dividend payments and distributions to PVR's minority unitholders of $13.8 million. In 2001, proceeds to the Company of $142.4 million from PVR's initial public offering allowed the Company to repay borrowings made for acquisitions after $7.9 million of dividend payments. In 2000, operating cash flows allowed the Company to repay debt of $30.3 million and to fund dividends of $7.4 million.

The Company has a $150 million secured revolving credit facility (the "Revolver") led by J.P. Morgan Chase Bank with a final maturity of October 2004. The credit facility has a borrowing base of $140 million and the Company had borrowings of $16.0 million and $3.5 million against the facility as of December 31, 2002 and 2001, respectively. The Revolver contains financial covenants requiring the Company to maintain certain levels of net worth, debt-to-capitalization and dividend limitation restrictions, among other requirements. We currently have a $5 million line of credit with a financial institution due in March 2003, renewable annually. We have the option to elect either a fixed rate LIBOR loan or floating rate LIBOR loan.

In connection with the closing of its initial public offering in 2001, PVR entered into a three-year credit agreement with a syndicate of financial institutions led by PNC Bank, National Association. The credit agreement consists of two facilities, a revolving credit facility of $50.0 million (the "PVR Revolver") and a term loan facility of up to $43.4 million (the "PVR Term Loan"). Both credit facilities mature in October 2004. The PVR Revolver is available for general partnership purposes, including working capital, capital expenditures, and acquisitions, and includes a $5.0 million distribution sublimit that is available for working capital needs and distributions and a $5.0 million sublimit for the issuance of letters of credit. In connection with the closing of its initial public offering, PVR borrowed $43.4 million under the PVR Term Loan and purchased and pledged $43.4 million of U.S. Treasury notes, which secured the term loan facility. In 2002, the U.S. Treasury Notes were liquidated for the purpose of funding acquisitions, and as of December 31, 2002, the obligations under the PVR Term Loan facility were unsecured. Total borrowings of as of December 31, 2002 against the PVR Revolver and PVR Term Loan were $47.5 million and $43.4 million, respectively. The PVR credit agreement contains financial covenants requiring the Partnership to certain levels of net worth and of debt to EBITDA (as defined by the credit agreement). The Partnership has the option to elect interest at i) LIBOR plus a Euro-rate margin of 0.5 percent, based on certain financial data, or (ii) the greater of the prime rate or federal funds rate plus .05 percent.

PVR is currently attempting to refinance up to $90 million of borrowings against its credit agreement with more permanent debt. This refinancing is expected to be completed by March 31, 2003, with proceeds used to repay and retire the PVR Term Loan and to repay most of the borrowings on the PVR Revolver. If the refinancing is not completed by March 31, 2003, PVR will be required to provide security to the syndicate of financial institutions in its credit agreement for all borrowings against its credit agreement.

Management believes its sources of funding are sufficient to meet short and long-term liquidity needs not funded by cash flows from operations.

Contractual Obligations

Our contractual obligations as of December 31, 2002, are as follows:

		Payments Due by Period			
(in thousands)	***Total***	***Less Than 1 Year***	***1-3 Years***	***4-5 Years***	***Thereafter***
Penn Virginia revolver	$ 16,000	$ –	$ 16,000	$ –	$ –
PVR revolver	47,500	–	47,500	–	–
PVR term loan	43,387	–	43,387	–	–
Line of credit	52	52	–	–	–
Rental commitments (1)	8,081	2,855	3,237	1,989	–
Total contractual cash obligations	$ 115,020	$ 2,907	$ 110,124	$ 1,989	$ –

(1) Rental commitments primarily relate to equipment, car and building leases. Also included are the Partnership's rental commitments, which primarily relate to reserve-based properties which are, or are intended to be, subleased by the Partnership to third parties. The obligation expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. We believe the obligation after five years cannot be reasonably estimated; however, based on current knowledge, we believe the Partnership will incur approximately $0.4 million in rental commitments in perpetuity until the reserves have been exhausted.

Environmental Matters

Our businesses are subject to various environmental hazards. Several federal, state and local laws, regulations and rules govern the environmental aspects of our businesses. Noncompliance with these laws, regulations and rules can result in substantial penalties or other liabilities. We do not believe our environmental risks are materially different from those of comparable companies nor that cost of compliance will have a material adverse effect on our profitability, capital expenditures, cash flows or competitive position. However, there is no assurance that future changes in or additions to laws, regulations or rules regarding the protection of the environment will not have such an impact. We believe we are materially in compliance with environmental laws, regulations and rules.

In conjunction with the Partnership's leasing of property to coal operators, environmental and reclamation liabilities are generally the responsibilities of the Partnership's lessees. Lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary.

Recent Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the asset.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is also added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

We will adopt the provisions of SFAS No. 143 effective January 1, 2003. We identified all required asset retirement obligations and determined the fair value of these obligations on the date of adoption. The determination of fair value was based upon regional market and specific well or mine type information. In conjunction with the initial application of SFAS No. 143, it is expected we will record a cumulative-effect of change in accounting principle, net of taxes, of approximately $0.5 to $1.5 million as an increase to income, which will be reflected in the Company's results of operations for 2003. In addition, it is expected we will record an asset retirement obligation of approximately $2.3 to $3.3 million.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* This Statement rescinds SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt,* which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item of debt to be aggregated and, if material, classified as an extraordinary item, net of income taxes. As a result, the criteria in Accounting Principles Board Opinion (APB) Opinion No. 30 will now be used to classify those gains and losses. Any gain or loss on the extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB Opinion No. 30 for classification as an extraordinary item shall be reclassified. The provisions of this Statement are effective for fiscal years beginning after January 1, 2003. The initial adoption of SFAS No. 145 did not have a material effect on the financial position, results of operations or liquidity of the Company.

In June 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This statement requires the recognition of costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this statement are effective for exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB issued Interpretation No. 45 (FIN 45), *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others,* which clarifies the requirements of SFAS No. 5, *Accounting for Contingencies,* relating to a guarantor's accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also will require certain guarantees that are issued or modified after December 31, 2002, including certain third-party guarantees, to be initially recorded on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. The financial statement recognition provisions are effective prospectively, and the Company cannot reasonably estimate the impact of adopting FIN 45 until guarantees are issued or modified in future periods, at which time their results will be initially reported in the financial statements...

Quantitative and Qualitative Disclosures about Market Risk

Interest Rate Risk. The carrying value of our debt approximates fair value. At December 31, 2002, we had $16.0 million of long-term debt represented by a secured revolving credit facility (the "PVA Revolver"). The PVA Revolver matures in October 2004 and is governed by a borrowing base calculation that is redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.375 to 1.875 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.375 to 0.875 percent. As a result, our 2003 interest costs will fluctuate based on short-term interest rates relating to the PVA Revolver.

Additionally, PVR had outstanding borrowings of $90.9 million, consisting of $47.5 million borrowed against its $50 million revolving credit facility (the "PVR Revolver") and $43.4 million of a fully-drawn term loan (the "PVR Term Loan"). Both the PVR Revolver and PVR Term Loan mature in October 2004. Regarding the unsecured PVR Revolver, PVR has the option to elect interest at (i) LIBOR plus a Euro-rate margin ranging from 1.25 to 1.75 percent, based upon certain financial data, or (ii) the greater of the prime rate or federal funds rate plus 0.5 percent. Regarding the PVR Term Loan, PVR has the option to elect interest at (i) LIBOR plus a Euro-rate margin of 0.5 percent, based upon certain financial data or (ii) the greater of the prime rate or federal funds rate plus 0.5 percent. As a result of both instruments, PVR's interest costs will fluctuate based on short-term interest rates.

Price Risk Management. Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to mitigate the price risks associated with fluctuations in natural gas and crude oil prices as they relate to our anticipated production. These contracts and/or financial instruments are designated as cash flow hedges and accounted for in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, as amended by SFAS No. 137 and SFAS No. 138. See Note 9 (Price Risk Management Activities) of the Notes to the Consolidated Financial Statements, for more information. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets are significantly affected by energy price fluctuations. As of February 14, 2003, our open commodity price risk management positions on average daily volumes were as follows:

Natural gas hedging positions	**Costless Collars**			**Swaps**	
		Price / MMBtu[a]			
	MMBtu Per Day	*Floor*	*Ceiling*	*MMBtu Per Day*	*Price/MMBtu*
First Quarter 2003	15,000	$ 3.15	$ 5.05	3,164	$ 4.70
Second Quarter 2003	21,500	$ 3.39	$ 5.36	3,399	$ 4.70
Third Quarter 2003	21,500	$ 3.39	$ 5.36	2,570	$ 4.70
Fourth Quarter 2003	19,500	$ 3.49	$ 5.46	2,034	$ 4.70
First Quarter 2004	19,500	$ 3.54	$ 5.51	1,800	$ 4.70
Second Quarter 2004	14,137	$ 3.56	$ 5.70	1,533	$ 4.70
Third Quarter 2004	1,348	$ 3.72	$ 6.97	1,367	$ 4.70
Fourth Quarter 2004	–	$ –	$ –	1,234	$ 4.70
First Quarter 2005 (January)	–	$ –	$ –	1,100	$ 4.70

(a) The costless collar natural gas prices per MMBtu per quarter include the effects of basis differentials, if any, that may be hedged.

Crude oil hedging positions	**Costless Collars**			**Swaps**	
		Price / Barrel			
	Barrels Per Day	*Floor*	*Ceiling*	*Barrels Per Day*	*Price/Barrel*
First Quarter 2003	500	$23.00	$28.75	150	$26.93
Second Quarter 2003	500	$23.00	$28.75	170	$26.93
Third Quarter 2003	–	$ –	$ –	250	$26.76
Fourth Quarter 2003	–	$ –	$ –	220	$26.74
First Quarter 2004	–	$ –	$ –	207	$26.73
Second Quarter 2004	–	$ –	$ –	193	$26.71
Third Quarter 2004	–	$ –	$ –	63	$26.93
Fourth Quarter 2004	–	$ –	$ –	57	$26.93
First Quarter 2005 (January)	–	$ –	$ –	50	$26.93

Forward-Looking Statements

Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions related thereto) are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. In addition, we and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements may include, among other things, statements regarding development activities, capital expenditures, acquisitions and dispositions, drilling and exploration programs, expected commencement dates and projected quantities of oil, gas, or coal production, as well as projected demand or supply for, coal and oil and natural gas, all of which may affect sales levels, prices and royalties realized by Penn Virginia and PVR.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting Penn Virginia and PVR and, therefore, involve a number of risks and uncertainties. Penn Virginia cautions that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Important factors that could cause the actual results of operations or financial condition of Penn Virginia to differ materially from those expressed or implied in the forward-looking statements include, but are not necessarily limited to: the cost of finding and successfully developing oil and gas reserves; the cost to PVR of finding new coal reserves; the ability of Penn Virginia to acquire new oil and gas reserves and of PVR to acquire new coal reserves on satisfactory terms; the price for which such reserves can be sold; the volatility of commodity prices for oil and gas and coal; the risks associated with having or not having price risk management programs; PVR's ability to lease new and existing coal reserves; the ability of PVR's lessees to produce sufficient quantities of coal on an economic basis from PVR's reserves; the ability of lessees to obtain favorable contracts for coal produced from PVR's reserves; Penn Virginia's ability to obtain adequate pipeline transportation capacity for its oil and gas production; competition among producers in the oil and gas and coal industries generally; the extent to which the amount and quality of actual production differs from estimated recoverable proved oil and gas reserves and coal reserves; unanticipated geological problems; availability of required materials and equipment; the occurrence of unusual weather or operating conditions including force majeure events; the failure of equipment or processes to operate in accordance with specifications or expectations; delays in anticipated start-up date of Penn Virginia's oil and natural gas production and PVR's lessees' mining operations; environmental risks affecting the drilling and producing of oil and gas wells or the mining of coal reserves; the timing of receipt of necessary governmental permits by Penn Virginia and by PVR's lessees; labor relations and costs; accidents; changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators; uncertainties relating to the outcome of mountaintop removal litigation and issues regarding coal truck weight restriction enforcement and legislation; risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions; and the experience and financial condition of lessees of PVR's coal reserves including their ability to satisfy their royalty, environmental, reclamation and other obligations to PVR and others. Many of such factors are beyond Penn Virginia's ability to control or predict. Readers are cautioned not to put undue reliance on forward-looking statements.

While Penn Virginia periodically reassesses material trends and uncertainties affecting Penn Virginia's results of operations and financial condition in connection with the preparation of Management's Discussion and Analysis of Results of Operations and Financial Condition and certain other sections contained in Penn Virginia's quarterly, annual or other reports filed with the Securities and Exchange Commission, Penn Virginia does not undertake any obligation to review or update any particular forward-looking statement, whether as a result of new information, future events or otherwise.

Signatures

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

PENN VIRGINIA CORPORATION

March 7, 2003	By: /s/ Frank A. Pici (Frank A. Pici, Executive Vice President and Chief Financial Officer)
March 7, 2003	By: /s/ Dana G. Wright (Dana G. Wright, Vice President and Principal Accounting Officer)

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

/s/ Robert Garrett (Robert Garrett)	Chairman of the Board and Director	March 7, 2003
/s/ Edward B Cloues, II (Edward B. Cloues, II)	Director	March 7, 2003
/s/ A. James Dearlove (A. James Dearlove)	Director and Chief Executive Officer	March 7, 2003
/s/ H. Jarrell Gibbs (H. Jarrell Gibbs)	Director	March 7, 2003
/s/ Keith D. Horton (Keith D. Horton)	Director and Executive Vice President	March 7, 2003
/s/ Marsha R. Perelman (Marsha R. Perelman)	Director	March 7, 2003
/s/ Joe T. Rye (Joe T. Rye)	Director	March 7, 2003
/s/ Gary K. Wright (Gary K. Wright)	Director	March 7, 2003

Certifications

I, A. James Dearlove, President and Chief Executive Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this annual report on Form 10-K of the Registrant;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the Registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors:

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant's ability to record, process, summarize and report financial data and have identified for the Registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal controls; and

6. The Registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 11, 2003

/s/ A. James Dearlove

A. James Dearlove
President and Chief Executive Officer

I, Frank A. Pici, Executive Vice President and Chief Financial Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this annual report on Form 10-K of the Registrant;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the Registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors:

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant's ability to record, process, summarize and report financial data and have identified for the Registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal controls; and

6. The Registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 11, 2003

/s/ Frank A. Pici

Frank A. Pici
Executive Vice President and Chief Financial Officer

Item 8 ⇒ Financial Statements and Supplementary Data

Penn Virginia Corporation and Subsidiaries

Index to Financial Section

Management's Report on Financial Information

Management of Penn Virginia Corporation (the "Company") is responsible for the preparation and integrity of the financial information included in this annual report. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, which involve the use of estimates and judgments where appropriate.

The Company has a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded against loss or unauthorized use and to produce the records necessary for the preparation of financial information. The system of internal control is supported by the selection and training of qualified personnel, the delegation of management authority and responsibility, and dissemination of policies and procedures. There are limits inherent in all systems of internal control based on the recognition that the costs of such systems should be related to the benefits to be derived. We believe the Company's systems provide this appropriate balance.

The Company's independent public accountants, KPMG LLP, have developed an understanding of our accounting and financial controls and have conducted such tests as they consider necessary to support their opinion on the 2002 financial statements. Their report contains an independent, informed judgment as to the corporation's reported results of operations and financial position for 2002.

The Board of Directors pursues its oversight role for the financial statements through the Audit Committee, which consists solely of outside directors. The Audit Committee meets regularly with management, the internal auditor and KPMG LLP, jointly and separately, to review management's process of implementation and maintenance of internal controls, and auditing and financial reporting matters. The independent and internal auditors have unrestricted access to the Audit Committee.

A. James Dearlove
President and Chief Executive Officer

Frank A. Pici
Executive Vice President and Chief Financial Officer

Independent Auditor's Report

To the Shareholders of Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheet of Penn Virginia Corporation (a Virginia corporation) and subsidiaries as of December 31, 2002, and the related consolidated statements of income, shareholders' equity and cash flows for the year then ended. 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 audit. The 2001 and 2000 consolidated financial statements of Penn Virginia Corporation and subsidiaries were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated February 18, 2002.

We conducted our audit 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 audit provides 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 Penn Virginia Corporation and subsidiaries as of December 31, 2002, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

Houston, Texas
February 14, 2003

THIS REPORT IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP. THE REPORT HAS NOT BEEN REISSUED BY ARTHER ANDERSEN LLP, NOR HAS ARTHUR ANDERSEN LLP PROVIDED A CONSENT TO THE INCLUSION OF ITS REPORT IN THIS FORM 10-K.

Report of Independent Public Accountants

To the Shareholders of Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation (a Virginia corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Houston, Texas
February 18, 2002

Penn Virginia Corporation and Subsidiaries
Consolidated Statements of Income

(in thousands, except share data)	**2002**	2001	2000
		Year Ended December 31,	
Revenues			
Oil and condensate	**$ 8,246**	$ 3,762	$ 832
Natural gas	**62,552**	53,263	46,019
Coal royalties	**31,358**	32,365	24,308
Timber	**1,640**	1,732	2,388
Dividends	**–**	198	2,646
Gain (loss) on the sale of properties	**(5)**	492	24,795
Other	**7,166**	4,759	5,010
	110,957	96,571	105,998
Expenses			
Lease operating	**12,754**	9,284	7,629
Exploration	**7,733**	11,832	5,660
Taxes other than income	**6,804**	5,433	3,648
General and administrative	**21,440**	15,297	11,350
Impairment of oil and gas properties	**796**	33,583	–
Depreciation, depletion and amortization	**30,639**	19,579	12,027
	80,166	95,008	40,314
Operating Income	**30,791**	1,563	65,684
Other income (expense)			
Interest expense	**(2,116)**	(2,453)	(7,926)
Interest income	**2,038**	1,602	1,458
Gain on the sale of securities	**–**	54,688	–
Other	**1**	14	14
Income from continuing operations before minority interest and income taxes anddiscontinued operations	**30,714**	55,414	59,230
Minority interest	**11,896**	1,763	–
Income tax expense	**6,935**	19,314	19,965
Income from continuing operations	**11,883**	34,337	39,265
Income from discontinued operations (including gain on sale and net of taxes)	**221**	–	–
Net Income	**$ 12,104**	$ 34,337	$ 39,265
Income from continuing operations per share, basic	**$ 1.33**	$ 3.92	$ 4.76
Income from discontinued operations per share, basic	**0.02**	–	–
Net Income per share, basic	**$ 1.35**	$ 3.92	$ 4.76
Income from continuing operation per share, diluted	**$ 1.32**	$ 3.86	$ 4.69
Income from discontinued operations per share, diluted	**0.02**	–	–
Net Income per share, diluted	**$ 1.34**	$ 3.86	$ 4.69
Weighted average shares outstanding, basic	**8,930**	8,770	8,241
Weighted average shares outstanding, diluted	**8,974**	8,896	8,371

The accompanying notes are an integral part of these consolidated financial statements.

Penn Virginia Corporation and Subsidiaries
Consolidated Balance Sheets

(in thousands, except share data)	*December 31,* **2002**	2001
Assets		
Current assets		
Cash and cash equivalents	$ 13,341	$ 9,621
Accounts receivable	20,366	12,334
Current portion of long-term notes receivable	527	599
Price risk management assets	–	3,674
Other	1,503	1,105
Total current assets	35,737	27,333
Property and equipment		
Oil and gas properties (successful efforts method)	383,360	335,494
Other property and equipment	265,180	117,789
	648,540	453,283
Less: Accumulated depreciation, depletion and amortization	102,588	72,095
Net property and equipment	545,952	381,188
Restricted U.S. Treasury Notes	–	43,387
Other assets	4,603	5,194
Total assets	$ 586,292	$ 457,102
Liabilities and Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 52	$ 1,235
Accounts payable	5,670	3,987
Accrued liabilities	16,508	10,762
Price risk management liabilities	1,621	–
Total current liabilities	23,851	15,984
Other liabilities	12,674	8,877
Deferred income taxes	62,154	55,861
Long-term debt	106,887	46,887
Minority interest	192,770	144,039
Commitments and contingencies (Note 20)		
Shareholders' equity		
Preferred stock of $100 par value – authorized 100,000 shares; none issued	–	–
Common stock of $6.25 par value – 16,000,000 shares authorized; 8,946,651 and 8,921,866 shares issued at December 31, 2002 and 2001 respectively	55,915	55,762
Paid-in capital	11,436	9,869
Retained earnings	123,189	119,125
Accumulated other comprehensive income	(1,661)	1,756
	188,879	186,512
Less: 23,765 shares of common stock held in treasury, at cost on December 31, 2001	–	599
Unearned compensation and ESOP	923	459
Total shareholders' equity	187,956	185,454
Total liabilities and shareholders' equity	$ 586,292	$ 457,102

The accompanying notes are an integral part of these consolidated financial statements.

Penn Virginia Corporation and Subsidiaries

Consolidated Statements of Shareholders' Equity

(in thousands, except share data)	*Shares Outstanding*	*Common Stock*	*Paid-in Capital*	*Retained Earnings*	*Accumulated Other Comprehensive Income*	*Treasury Stock*	*Unearned Compensation And ESOP*	*Total Stockholders' Comprehensive Equity*	*Comprehensive Income (Loss)*
Balance at December 31, 1999	8,423,628	$ 55,762	$ 8,096	$ 60,860	$ 42,017	$ (11,142)	$ (1,250)	$ 154,343	$ (9,464)
Dividends paid ($0.90 per share)	–	–	–	(7,407)	–	–	–	(7,407)	
Purchase of treasury stock	(363,430)	–	–	–	–	(6,761)	–	(6,761)	
Stock issued as compensation	11,163	–	–	–	–	226	–	226	
Exercise of stock options	326,397	–	(63)	–	–	6,703	–	6,640	
Allocation of ESOP shares	–	–	67	–	–	–	200	267	
Net income	–	–	–	39,265	–	–	–	39,265	39,265
Other comprehensive loss, net of tax	–	–	–	–	(15,411)	–	–	(15,411)	(15,411)
Balance at December 31, 2000	8,397,758	55,762	8,100	92,718	26,606	(10,974)	(1,050)	171,162	23,854
Dividends paid ($0.90 per share)	–	–	–	(7,930)	–	–	–	(7,930)	
Purchase of treasury stock	(33,991)	–	–	–	–	(638)	–	(638)	
Stock issued as compensation	8,281	–	142	–	–	188	–	330	
Exercise of stock options	526,053	–	1,417	–	–	11,216	–	12,633	
Allocation of ESOP shares	–	–	210	–	–	(391)	591	410	
Net income	–	–	–	34,337	–	–	–	34,337	34,337
Other comprehensive loss, net of tax	–	–	–	–	(24,850)	–	–	(24,850)	(24,850)
Balance at December 31, 2001	8,898,101	55,762	9,869	119,125	1,756	(599)	(459)	185,454	9,487
Dividends paid ($0.90 per share)	**–**	**–**	**–**	**(8,040)**	**–**	**–**	**–**	**(8,040)**	
Purchase of treasury stock	**(15,202)**	**–**	**–**	**–**	**–**	**(557)**	**–**	**(557)**	
Stock issued as compensation	**6,752**	**8**	**84**	**–**	**–**	**157**	**–**	**249**	
Penn Virginia Resource Partners, L.P. units issued as compensation, net	**–**	**–**	**806**	**–**	**–**	**–**	**(664)**	**142**	
Exercise of stock options	**57,000**	**145**	**470**	**–**	**–**	**999**	**–**	**1,614**	
Allocation of ESOP shares	**–**	**–**	**207**	**–**	**–**	**–**	**200**	**407**	
Net income	**–**	**–**	**–**	**12,104**	**–**	**–**	**–**	**12,104**	**12,104**
Other comprehensive loss, net of tax	**–**	**–**	**–**	**–**	**(3,417)**	**–**	**–**	**(3,417)**	**(3,417)**
Balance at December 31, 2002	**8,946,651**	**$ 55,915**	**$ 11,436**	**$ 123,189**	**$ (1,661)**	**$ –**	**$ (923)**	**$ 187,956**	**$ 8,687**

The accompanying notes are an integral part of these consolidated financial statements

Penn Virginia Corporation and Subsidiaries
Consolidated Statements of Cash Flow

(in thousands)	Year Ended December 31, **2002**	2001	2000
Cash flows from operating activities:			
Net income	**$ 12,104**	$ 34,337	$ 39,265
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	**30,639**	19,579	12,027
Impairment of oil and gas properties	**796**	33,583	–
Loss (gain) on the sale of property and equipment	**5**	(492)	(24,795)
Gain on sale of securities	**–**	(54,688)	–
Deferred income taxes	**8,133**	(1,888)	7,006
Tax benefit from stock option exercises	**230**	2,933	1,049
Dry hole and unproved leasehold expense	**2,255**	8,953	3,154
Minority interest	**11,896**	1,763	–
Noncash interest expense	**666**	285	112
Other	**1,074**	194	28
	67,798	44,559	37,846
Changes in operating assets and liabilities:			
Accounts receivable	**(5,695)**	592	(6,046)
Other current assets	**(646)**	(2,041)	161
Accounts payable and accrued liabilities	**6,849**	4,986	2,723
Taxes on income	**–**	(7,296)	7,296
Other assets and liabilities	**(2,518)**	3,391	(240)
Net cash flows provided by operating activities	**65,788**	44,191	41,740
Cash flows from investing activities:			
Proceeds from the sale of securities	**–**	57,525	–
Proceeds from the sale of property and equipment	**1,319**	1,416	55,208
Payments received on long-term notes receivable	**555**	1,052	926
Sale of restricted U. S. Treasury Notes	**43,387**	–	–
Purchase of restricted U.S. Treasury Notes	**–**	(43,387)	–
Additions to property and equipment	**(144,741)**	(196,038)	(59,443)
Net cash flows used in investing activities	**(99,480)**	(179,432)	(3,309)
Cash flows from financing activities:			
Dividends paid	**(8,040)**	(7,930)	(7,407)
Distributions paid to minority interest holders of subsidiary	**(13,787)**	–	–
Proceeds from borrowings	**22,046**	147,895	33,240
Repayment of borrowings	**(10,729)**	(191,400)	(63,509)
Proceeds from Penn Virginia Resource Partners, L.P. revolver	**47,500**	–	–
Proceeds from Penn Virginia Resource Partners, L.P. term loan	**–**	43,387	–
Proceeds from initial public offering, net	**–**	142,373	–
Purchases of treasury stock	**(557)**	(638)	(6,761)
Purchase of units of Penn Virginia Resource Partners, L.P.	**(1,067)**	–	–
Issuance of stock	**2,046**	10,440	6,084
Net cash flows provided by (used in) financing activities	**37,412**	144,127	(38,353)
Net increase in cash and cash equivalents	**3,720**	8,886	78
Cash and cash equivalents – beginning of year	**9,621**	735	657
Cash and cash equivalents – end of year	**$ 13,341**	$ 9,621	$ 735
Supplemental disclosures:			
Cash paid during the year for:			
Interest (net of amount capitalized)	**$ 1,213**	$ 3,131	$ 8,304
Income taxes	**$ 125**	$ 28,772	$ 4,614
Noncash additions to property and equipment:			
Issuance of Penn Virginia Resource Partners, L.P. units for acquisitions	**$ 50,920**	$ –	$ –
Working capital and assumed liabilities for acquisitions, net	**$ 3,805**	$ –	$ –
Deferred tax liabilities related to acquisition, net	**$ –**	$ 43,137	$ –

The accompanying notes are an integral part of these consolidated financial statements.

Penn Virginia Corporation and Subsidiaries
Notes to Consolidated Financial Statements

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia" or the "Company") is an independent energy company that is engaged in two primary lines of business. We explore for, develop and produce crude oil, condensate and natural gas in the eastern and southern portions of the United States. In addition, we conduct our coal operations through our ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"); a Delaware limited partnership. See Note 2 (Penn Virginia Resource Partners, L.P.).

The Partnership enters into leases with various third-party operators for the right to mine coal reserves on the Partnership's property in exchange for royalty payments. Coal royalty revenues under non-Peabody Leases are based on the higher of a percentage of the gross sales price or a fixed price per ton of coal sold, with pre-established minimum monthly or annual payments. Under the Peabody leases, coal royalty revenues are based on fixed royalty rates which escalate annually, also with pre-established monthly minimums. The Partnership also sells timber growing on its land and provides fee-based infrastructure facilities to certain lessees to enhance coal production and to generate additional coal services revenues.

2. Penn Virginia Resource Partners, L.P.

Penn Virginia Resource Partners, L.P. was formed in July 2001 to own and operate the coal land management business of Penn Virginia.

The Partnership completed its initial public offering of 7,475,000 common units at a price of $21.00 per unit on October 30, 2001. Total proceeds for the 7,475,000 units were $157.0 million before offering costs and underwriters' commissions. Effective with the closing of the initial public offering, Penn Virginia, through its wholly owned subsidiaries, received 174,880 common units, 7,649,880 subordinated units and a 2 percent partnership interest in the ownership of the Partnership. In addition, concurrent with the closing of the initial public offering, the Partnership borrowed $43.4 million under its term loan credit facility with PNC Bank, National Association and other lenders.

In conjunction with the formation of the Partnership, Penn Virginia contributed to the Partnership net assets totaling $39.1 million. Concurrent with the initial public offering, the Partnership paid $141.5 million to Penn Virginia for repayment of debt and the purchase of 975,000 common units held by Penn Virginia. The Partnership's note receivable from Penn Virginia was forgiven as well as the remaining portion of the Partnership's note payable to Penn Virginia.

The common units have preferences over the subordinated units with respect to cash distributions, accordingly, we accounted for the sale of the Partnership units as a sale of a minority interest. At the time our subordinated units convert to common units, we will recognize any gain or loss computed at that time, as paid-in capital. Our subordinated units automatically convert to common units on September 30, 2006, but a portion of the subordinated units may convert after September 30, 2004 if the Partnership meets certain financial tests, namely operating surpluses that exceed the minimum quarterly distributions.

In December 2002, the Partnership acquired approximately 120 million tons of coal reserves from subsidiaries of Peabody Energy Corporation ("Peabody"). In conjunction with the acquisition, the Partnership issued 1,522,325 common units and 1,240,833 Class B common units, of which 293,700 Class B common units are held in escrow pending certain title transfers. All Class B common units share in income and distributions on the same basis as the common units, but they are not listed on the New York Stock Exchange. Subject to the approval of our common unitholders, the Class B common units will automatically convert into an equal number of common units; however, if the conversion is denied, Peabody, as holder of the Class B units, would have the right to receive 115 percent of the amount of distributions paid on the common units. Adoption of the proposed conversion requires the affirmative vote of a majority of the votes cast at a special meeting of unitholders to be held in 2003, provided that the total votes cast represent over 50 percent in interest of all common units entitled to vote.

The general partner of the Partnership is Penn Virginia Resource GP, LLC (the "general partner"), a wholly owned subsidiary of Penn Virginia.

3. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Penn Virginia, all wholly-owned subsidiaries, and the Partnership in which we have an approximate 45 percent ownership interest as of December 31, 2002. Penn Virginia Resource GP, LLC, a wholly-owned subsidiary of Penn Virginia, serves as the Partnership's sole general partner and controls the Partnership. We own and operate our undivided oil and gas reserves through our wholly-owned subsidiaries. We account for our undivided interest in oil and gas properties using the proportionate consolidation method, whereby our share of assets, liabilities, revenues and expenses is included in the appropriate classification in the financial statements. Intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all adjustments have been reflected that are necessary for a fair presentation of the consolidated financial statements. Certain amounts have been reclassified to conform to the current year's presentation.

Use of Estimates

Preparation of the accompanying consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash equivalents/Restricted U.S. Treasury Notes

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. As of December 31, 2001, the Partnership had restricted cash in the form of U.S. Treasury Notes, which were used to secure the Partnership's term loan facility. See Note 11 (Long-Term Debt). In 2002, the Partnership sold the U.S. Treasury Notes and used the proceeds to purchase property and equipment.

Investments

During 2001 and 2000, we held investments that consisted of publicly traded equity securities. We classify our equity securities as available-for-sale. Available-for-sale securities are recorded at fair value based upon market quotations. Unrealized holding gains and losses, net of the related tax effect, on these securities are excluded from earnings and are reported as a separate component of stockholders' equity. See Note 18 (Accumulated Other Comprehensive Income). A decline in the market value of any available-for-sale security below cost that is deemed other than temporary, is charged to earnings in the period it occurs resulting in the establishment of a new cost basis for the security. Dividend income is recognized when received. Realized gains and losses for securities classified as available-for-sale are included in earnings and are derived using the specific identification method for determining the cost of securities sold. See Note 5 (Investments and Dividend Income).

Note Receivable

The note receivable is recorded at cost and adjusted for amortization of discounts. Discounts are amortized over the life of the note receivable using the effective interest rate method.

Oil and Gas Properties

We use the successful efforts method of accounting for our oil and gas operations. Under this method of accounting, costs to acquire mineral interests in oil and gas properties and to drill and equip development wells (including development dry holes) are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Cost of drilling exploratory wells are initially capitalized, and later charged to expense upon determination that the well does not justify commercial development. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred.

The costs of unproved leaseholds, incuding capitalized interest, are capitalized pending the results of exploration efforts. During 2002 and 2001, interest costs associated with non-producing leases were capitalized for the period activities were in progress to bring projects to their intended use. We capitalized $1.0 million and $1.1 million of interest costs in 2002 and 2001, respectively. No interest costs were capitalized in 2000. Unproved leasehold costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, the cost of the property has been impaired. As unproved leaseholds are determined to be productive, the related costs are transferred to proved leaseholds.

Other Property and Equipment

Other property and equipment is carried at cost and includes expenditures for additions and improvements, which substantially increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Depreciation of property and equipment is generally computed using the straight-line method over their estimated useful lives, varying from 3 years to 20 years. Coal properties are depleted on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. When an asset is retired or sold, its cost and related accumulated depreciation are removed from the accounts. The difference between undepreciated cost and proceeds from disposition is recorded as a gain or loss.

Impairment of Long-Lived Assets

We review our long-lived assets to be held and used, including proved oil and gas properties and the Partnership's coal properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss must be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we would recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the expected present value of future net cash flows from proved reserves, discounted utilizing a risk-free interest rate commensurate with the remaining lives for the respective oil and gas properties.

Concentration of Credit Risk

Substantially all of our accounts receivable at December 31, 2002 result from oil and gas sales and joint interest billings to third party companies in the oil and gas industry. This concentration of customers and joint interest owners may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral from a customer or joint interest owner, we analyze the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. Historical credit losses incurred on receivables have not been significant.

Substantially all of the Partnership's accounts receivable at December 31, 2002, result from billings to third party companies in the coal industry. This concentration of customers may impact the Partnership's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral from a lessee, the Partnership analyzes the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. Historical credit losses incurred by the Partnership on receivables have not been significant.

Risk Factors

Our revenues, profitability, cash flow and future growth rates are substantially dependent upon the price of and demand for natural gas and crude oil and to a lesser extent coal. Prices for natural gas and crude oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and crude oil, market uncertainty and a variety of additional factors that are beyond our control. We are also dependent upon the continued success of our exploratory drilling program. Other factors that could affect revenues, profitability, cash flow and future growth rates include the inherent uncertainties in crude oil, natural gas and coal reserves, hedging of our crude oil and natural gas production with derivative instruments, the ability to replace crude oil, natural gas and coal reserves, and finance future capital spending requirements.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, marketable securities, accounts receivable, notes receivables, U.S. Treasury Notes, accounts payable and long-term debt. The carrying values of cash, marketable securities, accounts receivables, U.S. Treasury Notes, accounts payables, and long-term debt approximate fair value. The fair value of notes receivable at December 31, 2002 and 2001 was $3.4 million and $4.6 million, respectively.

Revenues

Oil and Gas. Oil and gas sales revenues are recognized when crude oil and natural gas volumes are produced and sold for our account. Each working interest owner in a well generally has the right to a specific percentage of production, and often actual production sold for any particular owner will differ from their ownership percentage. When, under contract terms, these differences are settled in cash, revenues are adjusted accordingly.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenue from those sales. Most coal leases are based on minimum monthly or annual payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price.

Coal Services. Coal services revenues are recognized when lessees use the Partnership's facilities for the processing and transportation of coal. Coal services revenues consist of fees collected from the Partnership's lessees for the use of the Partnership's loadout facility, coal preparation plant, dock loading facility. Revenues associated with coal services for the years ended December 31, 2002 and 2001 were approximately $1.7 million for both years, and are included in other revenues.

Timber. Timber revenues are recognized as timber is sold on a contract basis where independent contractors harvest and sell the timber and, from time to time, in a competitive bid process involving sales of standing timber on individual parcels. Title and risk of loss pass to the independent contractors upon the execution of the contract. In addition, if the contractors do not harvest the timber within the specified time period, the title of the timber reverts back to the Partnership with no refund of original payment.

Minimum Rentals. Most of the Partnership's lessees must make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalty revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods (the recoupment period), the deferred income attributable to the minimum payment is recognized as minimum rental revenues. Revenues associated with minimum rentals are included in other revenues.

Income Tax

We account for income taxes in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes*. This Statement requires a company to recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in a company's financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates.

Stock-based Compensation

We have stock compensation plans that allow, among other grants, incentive and nonqualified stock options to be granted to key employees and officers and nonqualified stock options to be granted to directors. See Note 17 (Stock Compensation and Stock Ownership Plans). We account for those plans under the recognition and measurement principles of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provision of SFAS No. 123, *Accounting for Stock-Based Compensation*, to stock-based employee options.

(in thousands)	Year Ended December 31, **2002**	2001	2000
Net income, as reported	**$ 12,104**	$ 34,337	$ 39,265
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	**424**	215	147
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**(1,268)**	(900)	(320)
Pro forma net income	**$ 11,260**	$ 33,652	$ 39,092
Net income per share			
Basic – as reported	**$ 1.35**	$ 3.92	$ 4.76
Basic – pro forma	**$ 1.26**	$ 3.84	$ 4.74
Diluted – as reported	**$ 1.34**	$ 3.86	$ 4.69
Diluted – pro forma	**$ 1.25**	$ 3.78	$ 4.67

New Accounting Standards

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations,* which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the asset.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is also added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

We will adopt the provisions of SFAS No. 143 effective January 1, 2003. We identified all required asset retirement obligations and determined the fair value of these obligations on the date of adoption. The determination of fair value was based upon regional market and specific well or mine type information. In conjunction with the initial application of SFAS No. 143, it is expected we will record a cumulative-effect of change in accounting principle, net of taxes, of approximately \$0.5 to \$1.5 million as an increase to income, which will be reflected in the Company's results of operations for 2003. In addition, it is expected we will record an asset retirement obligation of approximately \$2.3 to \$3.3 million.

Effective January 1, 2002 we adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* This Statement supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of,* and the accounting and reporting provisions of APB No. 30, Reporting the Results of Operations – *Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions,* for the disposal of a segment of a business. SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. See Note 15 (Discontinued Operations) for current year disclosures related to our adoption.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* This Statement rescinds SFAS No. 4, *Reporting Gains and Losses from Extinguishment of Debt,* which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item of debt to be aggregated and, if material, classified as an extraordinary item, net of income taxes. As a result, the criteria in Accounting Principles Board Opinion (APB) Opinion No. 30 will now be used to classify those gains and losses. Any gain or loss on the extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB Opinion No. 30 for classification as an extraordinary item shall be reclassified. The provisions of this Statement are effective for fiscal years beginning after January 1, 2003. The initial adoption of SFAS No. 145 did not have a material effect on the financial position, results of operations or liquidity of the Company.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This Statement requires the recognition of costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this Statement are effective for exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB issued Interpretation No. 45 (FIN 45), *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others,* which clarifies the requirements of SFAS No. 5, Accounting for Contingencies, relating to a guarantor's accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also will require certain guarantees that are issued or modified after December 31, 2002, including certain third-party guarantees, to be initially recorded on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. The financial statement recognition provisions are effective prospectively, and the Company cannot reasonably estimate the impact of adopting FIN 45 until guarantees are issued or modified in future periods, at which time their results will be initially reported in the financial statements...

4. Acquisitions

Oil and gas

On January 22, 2003, we acquired a 25 percent non-operated working interest in properties located in a producing field in south Texas. Proved reserves of 31.8 billion cubic feet equivalent of (unaudited) were acquired in a cash transaction with a private investor group for \$32.5 million. The acquisition, which was effective January 1, 2003, was financed with the Company's existing credit facility. Nine wells are currently producing and comprise approximately one-third of the total proved reserves acquired. As of January 22, 2003, daily production net to the Company was approximately 11.4 million cubic feet (MMcf) of natural gas and 570 barrels of oil, or 14.8 MMcf equivalents (unaudited). Additional wells are expected to be drilled over the next two to three years to fully develop the field.

On July 23, 2001, we acquired all of the outstanding stock of Synergy Oil & Gas, Inc., a Texas corporation. Synergy was a privately owned independent exploration and production company with operations primarily in the Texas onshore Gulf Coast and West Texas areas. Cash consideration for the stock was approximately $112 million, which was funded by advances under our revolving credit facility and available cash on hand. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Synergy transaction based upon the fair values on the date of acquisition, as follows:

(in thousands)	
Value of oil and gas properties acquired	$ 157,120
Net assets acquired, excluding oil and gas properties	351
Deferred income tax liability	(45,271)
Cash paid, net of cash acquired	$ 112,200

The following unaudited Pro Forma results of operations have been prepared as though the acquisition had been completed on January 1, 2000. The unaudited Pro Forma results of operations for the years ended December 31, 2001 and 2000 are as follows:

(in thousands, except share data)	2001	2000
Revenues	$ 114,629	$ 128,127
Net income	$ 40,026	$ 33,773
Net income per share, diluted	$ 4.50	$ 4.03

Coal Royalty and Land Management

In December 2002, the Partnership acquired two properties containing approximately 120 million tons of coal reserves from Peabody for 1,522,325 million common units, 1,240,833 million Class B common units (a combined common unit value of $57.0 million) and $72.5 million in cash. The acquisition includes approximately $6.1 million, or 293,700 Class B units, which are currently held in escrow pending certain title transfers. As a result of the units held in escrow, approximately five million tons of coal reserves and 293,700 Class B common units were not included in property, plant and equipment or partners' capital, respectively, at December 31, 2002. The Class B common units will be converted to common units upon approval by the common unitholders. Approximately two-thirds of the reserves are located in New Mexico, which Peabody will continue to operate as a surface mining operation. Approximately one third of the acquired reserves are in northern West Virginia, which Peabody will also continue to operate. Each set of reserves is being leased back to Peabody for royalty rates which escalate annually over the life of the property's production. As part of the transaction, Peabody will receive the right to share in cash distributed with respect to the general partner's incentive distribution rights, if any, in exchange for additional properties Peabody may source to the Partnership in the future. The cash portion of the transaction was funded with long-term debt and $26.4 million in proceeds from the sale of U.S. Treasury notes. The acquired coal reserves had existing productive operations that have been included in the Partnership's statements of income since the closing date.

In November 2002, the Partnership completed the acquisition of certain infrastructure-related equipment and other assets integral to mining on its Fork Creek property in West Virginia. The purchased assets included a 900-ton per hour coal preparation plant, a unit-train loading facility and a railroad-granted rebate on coal loaded through the facility. The Partnership acquired the assets from Pen Holdings, Inc. and its lessors for $5.1 million in cash, which was funded with the proceeds from the sale of U.S. Treasury notes, plus the assumption of approximately $2.4 million in reclamation liabilities and approximately $0.6 million of stream mitigation obligations. The Partnership is actively seeking a new lessee and, as is customary in its operations, intends to assign all reclamation liabilities to such lessee. These assets did not have existing productive operations.

In August 2002, the Partnership acquired the mineral rights to approximately 16 million tons of coal reserves (unaudited) located in West Virginia for $12.3 million. The acquisition, which was purchased from an independent private entity, was funded with the proceeds from the sale of U.S. Treasury notes. The acquired mineral rights had existing productive operations that have been included in the Partnership's statements of income since the closing date.

In June 2001, the Partnership completed a $33.1 million acquisition from Pen Holdings, Inc., an unrelated third party. The acquisition contained 53 million tons of coal reserves in West Virginia (unaudited). The property had existing productive operations that have been included in the Partnership's statements of income since the closing date.

The factors used by the Partnership to determine the fair market value of acquisitions include, but are not limited to, discounted future net cash flows on a risked-adjusted basis, geographic location, quality of resources, potential marketability and financial condition of the lessees.

5. Investments and Dividend Income

In April 2001, we sold 3.3 million shares of the common stock of Norfolk Southern Corporation and other stocks which had been classified as available-for-sale. The Norfolk Southern Corporation shares were sold at an average price of $17.39 per share. Proceeds from the sales, net of commissions, totaled approximately $57.4 million. We recorded a pre-tax gain on the stock sale transactions of approximately $54.7 million.

Dividend income from our investment in Norfolk Southern Corporation was $0.2 million for the year ended December 31, 2001 and $2.6 million for the year ended December 31, 2000.

6. Notes Receivable

At December 31, 2002, we had one note receivable outstanding, which relates to the sale of coal properties located in Virginia in 1986. The note has a stated interest rate of 6.0 percent per annum and had an original principal amount of $15.0 million pursuant to which we receive quarterly payments through July 1, 2005. In addition, we own a 50 percent residual interest in any royalty income generated from the coal properties sold which are mined after July 1, 2005.

At December 31, 2001, we had an additional note relating to the sale of property and equipment in 1999 for which we received a $1.3 million note for a portion of the proceeds. This note was repaid in full in 2002.

Our note receivable is collateralized by property and equipment. Maturities of notes receivable are as follows:

	December 31,	
(in thousands)	**2002**	2001
Current	**$ 527**	$ 599
Due after one year through five years	**1,274**	1,757
Total	**$ 1,801**	$ 2,356

7. Property and Equipment

Property and equipment includes:

	December 31,	
(in thousands)	**2002**	2001
Oil and gas properties		
Unproved	**$ 57,575**	$ 57,813
Proved	**325,785**	277,681
Total oil and gas properties	**383,360**	335,494
Other property and equipment:		
Land and timber	**1,979**	1,961
Coal properties	**244,702**	106,270
Other equipment	**18,499**	9,558
Total property and equipment	**648,540**	453,283
Less: Accumulated depreciation, depletion and amortization	**(102,588)**	(72,095)
Net property and equipment	**$ 545,952**	$ 381,188

8. Impairment of Oil and Gas Properties

In accordance with SFAS No. 144, *Accounting for the Impairment of Disposal or Long-Lived Assets,* we review oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When we find that the carrying amounts of the properties exceed their estimated undiscounted future cash flows, we adjust the carrying amount of the properties to their fair value as determined by discounting its estimated future cash flows. For the twelve months ended December 31, 2002, we recognized a pretax charge of $0.8 million ($0.5 million after tax) related to the impairment of such properties. The factors used to determine fair value included, but were not limited to, estimates of proved reserves, future commodity prices, and timing of future production, future capital expenditures and a discount rate commensurate with the risk-free interest rate reflective of the lives remaining for the respective oil and gas properties.

Due to a low commodity price environment at the end of 2001, we recognized a non-cash pre-tax charge of $33.6 million ($21.8 million after tax) related to the impairment of oil and gas properties in the fourth quarter of 2001. There were no impairments of oil and gas properties in 2000.

9. Price Risk Management Activities

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas and crude oil price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of costless collars and swaps. All derivative financial instruments are recognized in the financial statements at fair value in accordance with SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138.

All derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we are utilizing only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. All hedge transactions are subject to our risk management policy, which has been reviewed and approved by the Board of Directors.

We formally document all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. We measure hedge effectiveness on a period basis. When it is determined that a derivative is not highly effective as a hedge, or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively.

Gains and losses on hedging instruments when settled are included in natural gas or crude oil production revenues in the period that the related production is delivered.

The fair values of our hedging instruments are determined based on third party forward price quotes for NYMEX Henry Hub and West Texas Intermediate closing prices as of December 31, 2002. The following table sets forth our positions as of December 31, 2002:

Time Period	*Notional Quantities*	*Effective Floor/Ceiling Price*	*Fair Value*
Natural Gas	**(MMbtu per Day)**	**(Per Mmbtu)**	**(in thousands)**
Costless collars			
January 1 – March 31, 2003	10,000	$ 3.01 / $ 5.01	$ (168)
January 1 – September 30, 2003	5,000	$ 3.37 / $ 5.05	(240)
April 1 – October 31, 2003	5,000	$ 2.92 / $ 4.42	(535)
October 2003	3,000	$ 3.50 / $ 5.00	(32)
November 1, 2003 – April 30, 2004	8,000	$ 3.50 / $ 5.00	(501)
April 1 2003 – June 30, 2004	7,500	$ 3.50 / $ 5.28	(445)
Crude Oil			
Costless collars	**(Bbls per Day)**	**(Per Bbl)**	
January 1 – June 30, 2003	500	$23.00 / $28.75	(144)
Total			**$(2,065)**

Based upon our assessment of our derivative contracts at December 31, 2002, we reported (i) an approximate liability of $2.1 million and (ii) a loss in accumulated other comprehensive income of $1.3 million, net of related income taxes of $0.8 million. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $1.0 million for the year ended December 31, 2002. Based upon future oil and natural gas prices as of December 31, 2002, $1.6 million of hedging losses are expected to be realized within the next 12 months. The amounts ultimately realized will vary due to changes in the fair value of the open derivative contracts prior to settlement. We recognized net hedging gains of $1.9 million for the year ended December 31, 2001. We had no outstanding derivative financial instruments at December 31, 2000.

As of February 14, 2003 our open commodity price risk management positions on average daily volumes were as follows:

Natural gas hedging positions	*Costless Collars*			*Swaps*	
		Price / MMBtu[a]			
	MMBtu Per Day	*Floor*	*Ceiling*	*MMBtu Per Day*	*Price/MMBtu*
First Quarter 2003	15,000	$ 3.15	$ 5.05	3,164	$ 4.70
Second Quarter 2003	21,500	$ 3.39	$ 5.36	3,399	$ 4.70
Third Quarter 2003	21,500	$ 3.39	$ 5.36	2,570	$ 4.70
Fourth Quarter 2003	19,500	$ 3.49	$ 5.46	2,034	$ 4.70
First Quarter 2004	19,500	$ 3.54	$ 5.51	1,800	$ 4.70
Second Quarter 2004	14,137	$ 3.56	$ 5.70	1,533	$ 4.70
Third Quarter 2004	1,348	$ 3.72	$ 6.97	1,367	$ 4.70
Fourth Quarter 2004	–	$ –	$ –	1,234	$ 4.70
First Quarter 2005 (January)	–	$ –	$ –	1,100	$ 4.70

(a) The costless collar natural gas prices per MMBtu per quarter include the effects of basis differentials, if any, that may be hedged.

Crude oil hedging positions	*Costless Collars*			*Swaps*	
		Price / Barrel			
	Barrels Per Day	*Floor*	*Ceiling*	*Barrels Per Day*	*Price/Barrel*
First Quarter 2003	500	$23.00	$28.75	150	$ 26.93
Second Quarter 2003	500	$23.00	$28.75	170	$ 26.93
Third Quarter 2003	–	$ –	$ –	250	$ 26.76
Fourth Quarter 2003	–	$ –	$ –	220	$ 26.74
First Quarter 2004	–	$ –	$ –	207	$ 26.73
Second Quarter 2004	–	$ –	$ –	193	$ 26.71
Third Quarter 2004	–	$ –	$ –	63	$ 26.93
Fourth Quarter 2004	–	$ –	$ –	57	$ 26.93
First Quarter 2005 (January)	–	$ –	$ –	50	$ 26.93

10. Accrued Liabilities

Accrued expenses are summarized as follows:

	December 31,	
(in thousands)	**2002**	2001
Deferred income	**$ 2,829**	$ –
Taxes other than income	**2,809**	2,700
Accrued oil and gas royalties	**2,513**	2,042
Compensation	**2,286**	1,949
Accrued drilling costs	**1,481**	1,641
Accrued professional services	**2,328**	53
Post-retirement healthcare	**160**	160
Pension	**140**	140
Other	**1,962**	2,077
Total	**$ 16,508**	$ 10,762

11. Long-Term Debt

Long-term debt as of December 31, 2002 and 2001 consisted of the following:

	December 31,	
(in thousands)	**2002**	2001
Penn Virginia revolving credit facility, variable rate of 2.8% at December 31, 2002, due in 2004	**$ 16,000**	$ 3,500
PVR revolving credit facility, variable rate of 3.2% at December 31, 2002, due in 2004	**47,500**	–
PVR Term loan, variable rates of 1.9% to 2.7% at December 31, 2002, due in 2004	**43,387**	43,387
Line of credit	**52**	1,235
	106,939	48,122
Less: current maturities	**(52)**	(1,235)
Total long-term debt	**$ 106,887**	$ 46,887

The aggregate maturities applicable to outstanding debt at December 31, 2002 are $52 thousand in 2003 and $106.9 million in 2004.

Penn Virginia Revolving Credit Facility

We have a $150.0 million secured revolving credit facility (the "Revolver") with a group of major banks, and a borrowing base of $140 million, which expires in October 2004.

The Revolver is governed by a borrowing base calculation and will be redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.375 to 1.875 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.375 to 0.875 percent. The weighted average interest rate on borrowings incurred during the year ended December 31, 2002 was approximately 3.0 percent. The Revolver allows for issuance of letters of credit that are limited to no more than $10 million. At December 31, 2002, letters of credit issued were $0.3 million. The financial covenants require us to maintain levels of net worth, debt-to-earnings and dividend limitation restrictions. We are currently in compliance with all of our covenants.

PVR Revolving Credit Facility

The Partnership has a $50.0 million unsecured revolving credit facility (the "Partnership Revolver") with a group of major banks, which expires in October 2004. The Partnership has the option to elect interest at (i) LIBOR plus a Euro-rate margin ranging from 1.25 percent to 1.75 percent, based on certain financial data or (ii) the greater of the prime rate or federal funds rate plus 0.5 percent. The Partnership Revolver allows for working capital draws of no more than $5.0 million and issuance of letters of credit, which are limited to $2 million. At December 31, 2002, letters of credit issued were $1.6 million. The financial covenants of the Partnership Revolver include, but are not limited to, maintaining: (i) a ratio of not more than 2.5:1.0 of total debt to consolidated EBITDA (as defined by the credit agreement) and (ii) a ratio of not less than 4.00:1.00 of consolidated EBITDA to interest. The Partnership is currently in compliance with all of its covenants.

PVR Term Loan

In conjunction with the PVR Revolver, the Partnership borrowed an additional $43.4 million in the form of a term loan. The term loan expires in October 2004. The Partnership has the option to elect interest at (i) LIBOR plus a Euro-rate margin 0.5 percent, based on certain financial data or (ii) the greater of the prime rate or federal funds rate plus 0.5 percent. The term loan was originally secured with U.S. Treasuries, but is currently unsecured, after the Treasuries were used to fund the Peabody Acquisition. The term loan is subject to the same covenants as the Revolver. The Partnership is currently in compliance with all of its covenants.

Line of Credit

We have a $5 million line of credit with a financial institution due in March 2003, renewable annually. We have an option to elect either a fixed rate LIBOR loan, floating rate LIBOR loan or base rate (as determined by the financial institution) loan.

Anticipated PVR Refinancing

The Partnership is currently attempting to refinance up to $90 million of its credit facility borrowings with more permanent debt. This refinancing is expected to be completed by March 31, 2003. If the refinancing is not completed by March 31, 2002, PVR will be required to provide security for all borrowings against its credit facility and term loan.

12. Income Taxes

The provision for income taxes from continuing operations is comprised of the following:

	Year ended December 31,		
(in thousands)	**2002**	2001	2000
Current income taxes			
Federal	**$ (320)**	$ 21,160	$ 10,463
State	**(878)**	42	2,496
Total current	**(1,198)**	21,202	12,959
Deferred income taxes			
Federal	**5,236**	(3,167)	6,951
State	**2,897**	1,279	55
Total deferred	**8,133**	(1,888)	7,006
Total income tax expense	**$ 6,935**	$ 19,314	$ 19,965

The difference between the taxes computed by applying the statutory tax rate to income from operations before income taxes and our reported income tax expense is as follows:

	Year Ended December 31,					
(in thousands)	2002		2001		2000	
Computed at federal statutory tax rate	**$ 6,586**	**35.0%**	$ 18,777	35.0%	$ 20,731	35.0%
State income taxes, net of federal income tax benefit	**1,312**	**7.0%**	859	1.6%	1,658	2.8%
Dividends received deduction	**–**	**–**	(49)	(0.1%)	(648)	(1.1%)
Non-conventional fuel source credit	**(926)**	**(4.9%)**	(721)	(1.3%)	(1,570)	(2.7%)
Other, net	**(37)**	**(0.2%)**	448	0.8%	(206)	(0.3%)
Total income tax expense	**$ 6,935**	**36.9%**	**$ 19,314**	**36.0%**	**$ 19,965**	**33.7%**

The principal components of our net deferred income tax liability are as follows:

	December 31,	
(in thousands)	2002	2001
Deferred tax assets:		
Pension and post-retirement benefits	**$ 1,826**	$ 1,513
Deferred income – coal properties	**965**	1,294
Alternative minimum tax credits	**–**	439
Net operating loss carryforwards	**1,392**	1,154
Other	**1,058**	74
Total deferred tax assets	**5,241**	4,474
Deferred tax liabilities:		
Notes receivable	**(668)**	(747)
Investments	**–**	–
Oil and gas properties	**(66,092)**	(56,675)
Other property and equipment	**(635)**	(2,108)
Other	**–**	(805)
Total deferred tax liabilities	**(67,395)**	(60,335)
Net deferred tax liability	**$ (62,154)**	$ (55,861)

As of December 31, 2002, we have various net operating loss carryforwards for state tax purposes of approximately $27.7 million which, if unused, will expire from 2009 to 2022.

13. Pension Plans and Other Post-retirement Benefits

We provide early retirement programs for eligible employees. Benefits are recorded based on the employee's average annual compensation and yearly services. We provided a noncontributory, defined benefit pension plan, which was frozen in 1996 and terminated in 2001.

We also sponsor a defined benefit post-retirement plan that covers employees hired prior to January 1, 1991 who retire from active service. The plan provides medical benefits for the retirees and dependents and life insurance for the retirees. The medical coverage is noncontributory for retirees who retired prior to January 1, 1991 and may be contributory for retirees who retired after December 31, 1990.

A reconciliation of the changes in the benefit obligations and fair value of assets for the two years ended December 31, 2002 and 2001 and a statement of the funded status at December 31, 2002 and 2001 is as follows:

	Pension		*Post-retirement Healthcare*	
(in thousands)	**2002**	2001	**2002**	2001
Reconciliation of benefit obligation:				
Obligation – beginning of year	**$ 2,375**	$ 10,467	**$ 3,468**	$ 2,853
Service cost	**–**	43	**10**	11
Interest cost	**164**	744	**311**	251
Benefits paid	**(260)**	(1,754)	**(618)**	(577)
Change in benefit assumption	**–**	–	**1,039**	–
Settlements	**–**	(7,879)	**–**	–
Actuarial (gain) loss	**98**	797	**750**	930
Other	**–**	(43)	**–**	–
Obligation – end of year	**2,377**	2,375	**4,960**	3,468
Reconciliation of fair value of plan assets:				
Fair value – beginning of year	**–**	9,941	**518**	975
Actual return on plan assets	**–**	368	**5**	138
Settlements	**–**	(7,879)	**–**	–
Employer contributions	**260**	259	**96**	10
Participant contributions	**–**	–	**11**	11
Benefit payments	**(260)**	(1,754)	**(609)**	(588)
Administrative expenses	**–**	(190)	**(21)**	(28)
Transfer to 401 K	**–**	(186)	**–**	–
Reversion to Penn Virginia	**–**	(559)	**–**	–
Fair value – end of year	**–**	–	**–**	518
Funded status:				
Funded status – end of year	**(2,377)**	(2,375)	**(4,960)**	(2,950)
Unrecognized transition obligation	**16**	20	**–**	–
Unrecognized prior service cost	**36**	42	**1,112**	79
Unrecognized (gain) loss	**491**	405	**1,559**	930
Net amount recognized	**$ (1,834)**	$ (1,908)	**$ (2,289)**	$ (1,941)

The following table provides the amounts recognized in the statements of financial position at December 31, 2002 and 2001:

	Pension		*Post-retirement Healthcare*	
(in thousands)	**2002**	2001	**2002**	2001
Accrued benefit liability	**$ (2,377)**	$ (2,375)	**$ (2,289)**	$ (1,941)
Other long-term assets	**52**	62	**–**	–
Accumulated other comprehensive income	**491**	405	**–**	–
Obligation – end of year	**$ (1,834)**	$ (1,908)	**$ (2,289)**	$ (1,941)

The following table provides the components of net periodic benefit cost for the plans for the two years ended December 31, 2002 and 2001:

	Pension		*Post-retirement Healthcare*	
(in thousands)	**2002**	2001	**2002**	2001
Service cost	**$ –**	$ 43	**$ 10**	$ 11
Interest cost	**164**	745	**311**	251
Expected return on plan assets	**–**	(901)	**(8)**	(23)
Amortization of prior service cost	**6**	6	**119**	6
Amortization of transitional obligation	**3**	3	**–**	–
Recognized actuarial (gain) loss	**12**	8	–	32
Net periodic benefit cost	**$ 185**	$ (96)	**$ 432**	$ 277

The assumptions used in the measurement of our benefit obligation were as follows:

	Pension		*Post-retirement Healthcare*	
(in thousands)	**2002**	2001	**2002**	2001
Discount rate	**6.75%**	7.25%	**6.75%**	7.25%
Expected return on plan assets	**–**	9.50	**–**	3.00

For measurement purposes, a 9.5 percent annual rate increase in the per capita cost of covered health care benefits was assumed for 2002. The rate is assumed to decrease gradually to 5.0 percent for 2011 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for post-retirement benefits. A one percent change in assumed health care cost trend rates would have the following effects for 2002:

(in thousands)	One percent Increase	One percent Decrease
Effect on total of service and interest cost components	$ 14	$ (12)
Effect on post-retirement benefit obligation	157	(144)

14. Other Liabilities

Other liabilities are summarized in the following table:

	December 31,	
(in thousands)	**2002**	2001
Reclamation/environmental liabilities	**$ 5,349**	$ 1,154
Post-retirement health care	**2,129**	1,781
Deferred income	**2,488**	3,658
Pension	**2,237**	2,234
Other	**471**	50
Total	**$ 12,674**	$ 8,877

15. Discontinued Operations

During the second quarter of 2002, we sold certain oil and gas properties, which included various interests in south Texas properties acquired in the third quarter of 2001. The operations of these properties were insignificant in 2001. The net carrying amount of properties sold was approximately $0.5 million. Accordingly, under the provisions of SFAS No. 144 the components of discontinued operations were as follows for the year ended December 31, 2002:

Production	
Oil and condensate (Mbbls)	16
Natural gas (MMcf)	18
Total production (MMcfe)	114
Revenues	
Natural gas	$ 48
Oil and condensate	332
Total revenues	380
Expenses	
Operating expenses	352
Depreciation, depletion and amortization	25
Total expenses	377
Income from discontinued operations	3
Gain on sale of properties	337
	340
Income taxes	(119)
Net income from discontinued operations	$ 221

16. Earnings Per Share

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share ("EPS") for net income for the three years ended December 31, 2002 .

	Year ended December 31,		
(in thousands, except for per share data)	**2002**	**2001**	**2000**
Income from continuing operations	**$ 11,883**	$ 34,337	$ 39,265
Income from discontinued operations	**221**	–	–
Net income	**$ 12,104**	$ 34,337	$ 39,265
Weighted average shares, basic	**8,930**	8,770	8,241
Effect of dilutive securities:			
Stock options	**44**	126	130
Weighted average shares, diluted	**8,974**	8,896	8,371
Income from continuing operations per share, basic	**$ 1.33**	$ 3.92	$ 4.76
Income from discontinued operations per share, basic	**0.02**	–	–
Net income per share, basic	**$ 1.35**	$ 3.92	$ 4.76
Income from continuing operations per share, diluted	**$ 1.32**	$ 3.86	$ 4.69
Income from discontinued operations per share, diluted	**0.02**	–	–
Net income per share, diluted	**$ 1.34**	$ 3.86	$ 4.69

17. Stock Compensation and Stock Ownership Plans

Stock Compensation Plans

We have several stock compensation plans (collectively known as the "Stock Compensation Plans") that allow, among other grants, incentive and nonqualified stock options to be granted to key employees and officers and nonqualified stock options to be granted to directors. Options granted under the Stock Compensation Plans may be exercised at any time after one year and prior to ten years following the grant, subject to special rules that apply in the event of death, retirement and/or termination of the employment of an optionee. The exercise price of all options granted under the Stock Compensation Plans is at the fair market value of the Company's stock on the date of the grant. At December 31, 2002 there were approximately 134,000 and 416,000 shares available for issuance to directors and employees, respectively, pursuant to the Stock Compensation Plans.

The following table summarizes information with respect to the common stock options awarded under the Stock Option Plans and grants described above.

	2002		2001		2000	
	Shares Under Options	***Weighted Avg. Exercise Price***	*Shares Under Options*	*Weighted Avg Exercise Price*	*Shares Under Options*	*Weighted Avg Exercise Price*
Outstanding at beginning of year	**359,450**	**$ 25.97**	725,403	$ 19.38	1,014,500	$ 18.74
Granted	**113,400**	**$ 36.91**	160,100	$ 32.02	46,300	$ 16.65
Exercised	**57,000**	**$ 24.45**	526,053	$ 23.35	326,397	$ 17.13
Cancelled	**12,000**	**$ 21.38**	–	–	9,000	$ 18.99
Outstanding at end of year	**403,850**	**$ 29.39**	359,450	$ 25.97	725,403	$ 19.38
Weighted average of fair value of options granted during the year		**$ 10.17**		$ 10.55		$ 5.02

The fair value of the options granted during 2002 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 2.37 percent to 2.66 percent, b) expected volatility of 28.6 percent, c) risk-free interest rate 3.8 percent and d) expected life of eight years.

The fair value of the options granted during 2001 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 2.71 percent to 2.92 percent, b) expected volatility of 32.3 percent, c) risk-free interest rate of 5.1 percent and d) expected life of eight years.

The fair value of the options granted during 2000 is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: a) dividend yield of 5.2 percent to 5.4 percent, b) expected volatility of 37.0 percent, c) risk-free interest rate of 6.9 percent to 7.0 percent and d) expected life of eight years.

The following table summarizes certain information regarding stock options outstanding at December 31, 2002:

	Options Outstanding			*Options Exercisable*	
Range of Exercise Price	*Number Outstanding at 12/31/02*	*Weighted Avg. Remaining Contractual Life*	*Weighted Avg. Exercise Price*	*Number Exercisable at 12/31/02*	*Weighted Avg. Exercise Price*
$ 15 to $ 19	44,800	5.9	$ 17.76	44,800	$ 17.76
$ 20 to $ 24	88,500	4.9	$ 21.87	88,500	$ 21.87
$ 25 to $ 29	23,050	6.0	$ 27.09	23,050	$ 27.09
$ 30 to $ 34	145,300	8.8	$ 32.43	134,100	$ 32.27
$ 35 to $ 39	102,200	9.4	$ 37.19	–	$ –

Employees' Stock Ownership Plan

In 1996, the Board of Directors extended the Employees' Stock Ownership Plan ("ESOP"). All employees with one year of service are participants. The ESOP is designed to enable employees to accumulate stock ownership. While there are no employee contributions, participants receive an allocation of stock which has been contributed by the Company. Compensation costs are reported when such shares are released to employees. The ESOP borrowed $2.0 million from the Company in 1996 and used the proceeds to purchase treasury stock. Under the terms of the ESOP, we will make annual contributions over a 10-year period. At December 31, 2002, the unearned portion of the ESOP of approximately ($0.3 million) is reported as a component of Shareholders' Equity entitled "Unearned Compensation-ESOP."

Shareholder Rights Plan

In February 1998, the Board of Directors adopted a Shareholder Rights Plan (the "Plan") designed to prevent an acquirer from gaining control of the Company without offering a fair price to all shareholders. The Plan was amended in March 2002. Each right entitles the holder to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock, $100 par value, at a price of $100 subject to adjustment. The rights are not exercisable or transferable apart from the common stock until after a person or affiliated group has acquired or obtained the right to acquire fifteen percent or more (or ten percent or more if such person or group has been deemed to an "adverse person" as defined in the Plan), of our common stock. Each right will entitle the holder, under certain circumstances, to acquire at half the value, either common stock of the Company, a combination of cash, other property, or common stock or other securities of the Company, or common stock of an acquiring person. Any such event would also result in any rights owned beneficially by the acquiring person or its affiliates becoming null and void. The rights expire in February 2008 and are redeemable under certain circumstances.

Restricted Units

The general partner granted 37,500 restricted units to directors and officers of the general partner in 2002. A restricted unit entitles the grantee to receive a common unit upon the vesting of the restricted unit. Restricted units vest upon terms established by the Partnership Compensation Committee, but in no case earlier than the conversion to common units of the Partnership's outstanding subordinated units. In addition, the restricted units will vest upon a change of control of the general partner or the Company. If a grantee's employment with or membership on the Partnership's Board of Directors of the general partner terminates for any reason, the grantee's restricted units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise. Common units to be delivered upon the vesting of restricted units may be common units acquired by the general partner in the open market, common units already owned by the general partner, common units acquired by the general partner directly from the Partnership or any other person or any combination of the foregoing. The general partner will be entitled to reimbursement by the Partnership for the cost incurred in acquiring such common units. Distributions payable with respect to restricted units may, at the Partnership's Compensation Committee's request, be paid directly to the grantee or held by the Partnership and made subject to a risk of forfeiture during the applicable restriction period.

The following table summarizes information with respect to restricted units awarded by the general partner.

	2002	
	Restricted Units	Fair Value
Outstanding at beginning of year	–	$ –
Granted	37,500	$ 24.50
Vested	4,000	$ 24.50
Forfeited	–	–
Outstanding at end of year	33,500	$ 24.50

18. Accumulated Other Comprehensive Income

Comprehensive income represents certain changes in equity during the reporting period, including net income and other comprehensive income, which includes, but is not limited to, unrealized gains from marketable securities, price risk management assets and minimum pension liability adjustments. Reclassification adjustments represent gains or losses realized in net income for each respective year. For the three years ended December 31, 2002, the components of accumulated other comprehensive income are as follows:

(in thousands)	*Net unrealized holding gain – Investments*	*Price risk management assets*	*Minimum pension liability*	*Accumulated other comprehensive income*
Balance at December 31, 1999	$ 42,235	$ –	$ (218)	$ 42,017
Unrealized holding loss, net of tax of $8,308	(15,429)	–	–	(15,429)
Pension plan adjustment, net of tax of $10	–	–	18	18
Balance at December 31, 2000	26,806	–	(200)	26,606
Investment holding gain, net of tax of $1,383	8,741	–	–	8,741
Investment reclassification adjustment, net of tax of $19,140	(35,547)	–	–	(35,547)
Price risk management unrealized gain, net of tax of $1,940	–	3,603	–	3,603
Price risk management reclassification adjustment, net of tax of $853	–	(1,584)	–	(1,584)
Pension plan adjustment, net of tax of $34	–	–	(63)	(63)
Balance at December 31, 2001	–	2,019	(263)	1,756
Price risk management unrealized loss, net of tax of $2,160	**–**	**(4,012)**	**–**	**(4,012)**
Price risk management reclassification adjustment, net of tax of $350	**–**	**651**	**–**	**651**
Pension plan adjustment, net of tax of $30	**–**	**–**	**(56)**	**(56)**
Balance at December 31, 2002	**$ –**	**$(1,342)**	**$(319)**	**$ (1,661)**

19. Segment Information

Segment information has been prepared in accordance with SFAS No. 131 *Disclosure about Segments of an Enterprise and Related Information.* Under SFAS No. 131, operating segments are defined as components of an enterprise about which separate financial information is available and is evaluated regularly by the chief decision maker, or decision-making group, in assessing performance. Our chief operating decision-making group consists of the Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our oil and gas operations and its coal royalty and land management operations. Accordingly, our reportable segments are as follows:

- Oil and Gas – crude oil and natural gas exploration, development and production.
- Coal Royalty and Land Management – the leasing of mineral rights and subsequent collection of royalties and the development and harvesting of timber.
- All Other – primarily represents corporate functions.

(in thousands)	*Oil and Gas*	*Coal Royalty Land Management*	*All Other*	*Consolidated*
December 31, 2002				
Revenues	$ 71,512	$ 38,608	$ 837	$ 110,957
Operating costs and expenses	30,801	10,226	7,704	48,731
Depreciation, depletion and amortization	26,336	3,955	348	30,639
Impairment of oil and gas properties	796	–	–	796
Operating income (loss)	$ 13,579	$ 24,427	$ (7,215)	30,791
Interest expense				(2,116)
Interest income				2,038
Other				1
Income before minority interest and taxes				$ 30,714
Total assets	$ 314,284	$ 266,576	$ 5,432	$ 586,292
Capital expenditures	$ 51,581	$ 92,817	$ 343	$ 144,741
December 31, 2001				
Revenues	$ 57,778	$ 37,513	$ 1,280	$ 96,571
Operating costs and expenses	26,914	9,271	5,661	41,846
Depreciation, depletion and amortization	16,418	3,084	77	19,579
Impairment of oil and gas properties	33,583	–	–	33,583
Operating income (loss)	$ (19,137)	$ 25,158	$ (4,458)	1,563
Gain on sale of securities				54,688
Interest expense				(2,453)
Interest income				1,602
Other				14
Income before minority interest and taxes				$ 55,414
Total assets	$ 289,379	$ 162,638	$ 5,085	$ 457,102
Capital expenditures	$ 161,295	$ 33,669	$ 1,074	$ 196,038
December 31, 2000				
Revenues	$ 71,405	$ 30,189	$ 4,404	$ 105,998
Operating costs and expenses	15,107	8,327	4,853	28,287
Depreciation, depletion and amortization	9,883	2,047	97	12,027
Operating income (loss)	$ 46,415	$ 19,815	$ (546)	65,684
Interest expense				(7,926)
Interest income				1,458
Other				14
Income before taxes				$ 59,230
Total assets	$ 142,613	$ 79,803	$ 46,350	$ 268,766
Capital expenditures	$ 58,677	$ 485	$ 281	$ 59,443

Operating loss for the Oil Gas segment in 2001 includes a $33.6 million impairment on properties see Note 9 (Impairment of Oil and Gas Properties). Operating income for 2000 includes a gain on sale of property of $23.9 million.

Operating income is total revenue less operating expenses. Operating income does not include certain other income items, gain (loss) on sale of securities, interest expense, minority interest and income taxes.

For the year ended December 31, 2002, two customers of the oil and gas segment accounted for $29.4 million, or 26 percent, and $17.7 million, or 16 percent, respectively, of our consolidated net revenues. For the year ended December 31, 2001, two customers of the oil and gas segment accounted for $20.8 million, or 22 percent, and $11.4 million, or 12 percent, respectively, of our consolidated net revenues.

20. Commitments and Contingencies

Rental Commitments

Minimum rental commitments under all non-cancelable operating leases, primarily real estate, in effect at December 31, 2002 were as follows:

(in thousands)	*Year ending December 31,*
2003	$ 2,855
2004	1,729
2005	1,508
2006	1,388
2007	601
Total minimum payments	$ 8,081

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, management believes these claims will not have a material effect on the financial position, liquidity or operations.

Environmental Compliance

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

The operations of the Partnership's lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of the Partnership's coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified the Partnership against any and all future environmental liabilities. The Partnership regularly visits the coal property leases to monitor its lessee's compliance with environmental laws and regulations, as well as to review mining activities. Management believes that the Partnership's lessees will be able to comply with existing regulations and does not expect any material impact on its financial condition or results of operations as a result of environmental regulations.

With respect to its unleased and inactive properties, the Partnership has some reclamation bonding requirements. In conjunction with the November 2002 purchase of equipment at the Fork Creek property, the Partnership assumed reclamation and mitigation liabilities of approximately $3.0 million. The Partnership is currently pursuing a potential lessee for this property and, as is customary in its operations, the Partnership intends to assign all reclamation liabilities to such lessee. As of December 31, 2002 and 2001, the Partnership's environmental liabilities totaled $4.6 million and zero, respectively.

21. Quarterly Financial Information (Unaudited)

Summarized Quarterly Financial Data:

(in thousands, except share data)	2002 Quarters Ended Mar. 31	June 30	Sept. 30	Dec. 31	2001 Quarters Ended Mar. 31	June 30[a]	Sept. 30	Dec. 31[b]
Revenues	**$ 24,383**	**$ 25,648**	**$ 28,754**	**$ 32,172**	$ 27,121	$ 24,741	$ 24,031	$ 20,678
Operating Income (loss)[c]	**$ 8,778**	**$ 7,076**	**$ 7,949**	**$ 6,988**	$ 16,958	$ 13,461	$ 6,841	$ (35,697)
Net income	**$ 3,370**	**$ 3,163**	**$ 3,208**	**$ 2,363**	$ 10,710	$ 43,018	$ 4,247	$ (23,638)
Net income from continuing operations per share[d]								
Basic	**$ 0.38**	**$ 0.33**	**$ 0.36**	**$ 0.26**	$ 1.25	$ 4.88	$ 0.48	$ (2.66)
Diluted	**$ 0.37**	**$ 0.33**	**$ 0.36**	**$ 0.26**	$ 1.22	$ 4.79	$ 0.47	$ (2.63)
Net income from per share[d]								
Basic	**$ 0.38**	**$ 0.35**	**$ 0.36**	**$ 0.26**	$ 1.25	$ 4.88	$ 0.48	$ (2.66)
Diluted	**$ 0.37**	**$ 0.35**	**$ 0.36**	**$ 0.26**	$ 1.22	$ 4.79	$ 0.47	$ (2.63)
Weighted average shares outstanding:								
Basic	**8,909**	**8,927**	**8,944**	**8,945**	8,549	8,820	8,869	8,890
Diluted	**9,007**	**8,984**	**8,982**	**8,984**	8,755	8,982	9,007	8,989

(a) Net income for the second quarter of 2001 included a $54.7 million ($35.6 million after tax) gain on the sale of Norfolk Southern Corporation Common Stock.

(b) Operating loss for the fourth quarter of 2001 included a $33.6 million impairment on oil and gas properties.

(c) Certain reclassifications have been made to conform to the current year presentation.

(d) The sum of the quarters may not equal the total of the respective year's net income per share due to changes in the weighted average shares outstanding throughout the year.

22. Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The following supplementary information regarding the oil and gas producing activities is presented in accordance with the requirements of the Securities and Exchange Commission (SEC) and SFAS No. 69 "Disclosures about Oil and Gas Producing Activities". The amounts shown include our net working and royalty interest in all of our oil and gas operations.

Capitalized Costs Relating to Oil and Gas Producing Activities

(in thousands)	Year Ended December 31, 2002	2001	2000
Proved properties	**$ 73,606**	$ 75,152	$ 64,107
Unproved properties	**57,575**	57,813	2,425
Wells, equipment and facilities	**248,746**	199,670	105,283
Support equipment	**3,433**	2,859	2,689
	383,360	335,494	174,504
Accumulated depreciation and depletion	**(86,586)**	(60,073)	(43,720)
Net capitalized costs	**$ 296,774**	$ 275,421	$ 130,784

Costs Incurred in Certain Oil and Gas Activities

(in thousands)	Year Ended December 31, 2002	2001	2000
Proved property acquisition costs	**$ 517**	$ 97,143	$ 35,999
Unproved property acquisition costs	**6,829**	64,488	917
Exploration costs	**7,843**	13,814	5,125
Development costs and other	**41,750**	31,545	18,561
Total costs incurred	**$ 56,939**	$ 206,990	$ 60,602

Costs for the year ended December 31, 2001, include deferred income taxes of $45.3 million provided for the book versus tax basis difference related to the acquired Synergy Oil and Gas properties, $27.2 million of which is included in proved property acquisition costs and $18.1 million is included in unproved property acquisition costs.

Results of Operations for Oil and Gas Producing Activities

The following schedule includes results solely from the production and sale of oil and gas and a non-cash charge for property impairments. It excludes corporate related general and administrative expenses and gains or losses on property dispositions. The income tax expense is calculated by applying the statutory tax rates to the revenues after deducting costs, which include depletion allowances and giving effect to oil and gas related permanent differences and tax credits.

(in thousands)	Year Ended December 31, 2002	2001	2000
Revenues	**$ 71,178**	$ 57,024	$ 46,851
Production expenses	**15,390**	10,069	7,226
Exploration expenses	**7,614**	11,514	5,080
Depreciation and depletion expense	**26,361**	16,418	9,883
Impairment of oil and gas properties	**796**	33,583	–
	21,017	(14,560)	24,662
Income tax expense (benefit)	**6,566**	(5,817)	8,309
Results of operations	**$ 14,451**	$ (8,743)	$ 16,353

Oil and Gas Reserves

The following schedule presents the estimated oil and gas reserves owned by us. This information includes our royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the three years ended December 31, 2002, were estimated by Wright and Company, Inc. All reserves are located in the United States.

There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved oil and gas reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed oil and gas reserves are those reserves expected to be recovered through existing equipment and operating methods.

Net quantities of proved reserves and proved developed reserves during the periods indicated are set forth in the tables below:

Proved Developed and Undeveloped Reserves

	Oil and Condensate (MBbls)	*Natural Gas (MMcf)*	*MMcfe*
December 31, 1999	359	185,198	187,352
Revisions of previous estimates	107	(1,893)	(1,251)
Extensions, discoveries and other additions	19	30,987	31,101
Production	(31)	(11,645)	(11,831)
Purchase of reserves	11	35,879	35,945
Sale of reserves in place	(394)	(64,279)	(66,643)
December 31, 2000	71	174,247	174,673
Revisions of previous estimates	(438)	(5,697)	(8,325)
Extensions, discoveries and other additions	90	41,395	41,935
Production	(164)	(13,130)	(14,114)
Purchase of reserves	4,361	33,402	59,568
Sale of reserves in place	–	(964)	(964)
December 31, 2001	3,920	229,253	252,773
Revisions of previous estimates	**–**	**(3,339)**	**(3,339)**
Extensions, discoveries and other additions	**1,944**	**33,197**	**44,861**
Production	**(364)**	**(18,715)**	**(20,899)**
Purchase of reserves	**29**	**1,071**	**1,245**
Sale of reserves in place	**(168)**	**(212)**	**(1,220)**
December 31, 2002	**5,361**	**241,255**	**273,421**
Proved Developed Reserves:			
December 31, 2000	71	145,930	146,356
December 31, 2001	2,212	183,134	196,406
December 31, 2002	**2,943**	**198,733**	**216,391**

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and gas reserves. Future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas reserves. Natural gas prices were escalated only where existing contracts contained fixed and determinable escalation clauses. Contractually provided natural gas prices in excess of estimated market clearing prices were used in computing the future cash inflows only if we expect to continue to receive higher prices under legally enforceable contract terms. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved oil and gas reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10 percent annual rate.

	Year Ended December 31,		
(in thousands)	**2002**	2001	2000
Future cash inflows	**$ 1,372,935**	$ 722,203	$ 1,727,923
Future production costs	**263,705**	178,533	205,385
Future development costs	**51,151**	39,145	19,981
Future net cash flows before income tax	**1,058,079**	504,525	1,502,557
Future income tax expense	**285,633**	127,277	422,485
Future net cash flows	**772,446**	377,248	1,080,072
10% annual discount for estimated timing of cash flows	**417,523**	188,305	612,679
Standardized measure of discounted future net cash flows	**$ 354,923**	$ 188,943	$ 467,393

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in thousands)	**2002**	2001	2000
Sales of oil and gas, net of production costs	**$ (55,788)**	$ (47,191)	$ (39,754)
Net changes in prices and production costs	**203,588**	(483,009)	313,355
Extensions, discoveries and other additions	**82,808**	37,907	123,223
Development costs incurred during the period	**16,393**	13,771	16,001
Revisions of previous quantity estimates	**(6,513)**	(7,710)	(4,604)
Purchase of minerals-in-place	**2,901**	70,294	121,979
Sale of minerals-in-place	**(328)**	(906)	(41,456)
Accretion of discount	**24,254**	64,363	13,628
Net change in income taxes	**(72,614)**	122,636	(159,220)
Other changes	**(28,721)**	(48,605)	4,978
Net increase (decrease)	**165,980**	(278,450)	348,130
Beginning of year	**188,943**	467,393	119,263
End of year	**$ 354,923**	$ 188,943	$ 467,393

As required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," changes in standardized measure relating to sales of reserves are calculated using prices in effect as of the beginning of the period and changes in standardized measure relating to purchases of reserves are calculated using prices in effect at the end of the period. Accordingly, the changes in standardized measure for purchases and sales of reserves reflected above do not necessarily represent the economic reality of such transactions. See the disclosure of "Costs incurred in Certain Oil and Gas Activities" and the statements of cash flows in the financial statements.

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

Effective May 3, 2002, the Audit Committee of the Board of Directors of our Company dismissed Arthur Andersen LLP ("Andersen") as the Company's independent public accountants and engaged KPMG to serve as the Company's independent public accountants for 2002.

None of Andersen's reports on the Company's consolidated financial statements for either of the past two fiscal years contained an adverse opinion or disclaimer of opinion or were qualified or modified as to uncertainty, audit scope or accounting principles.

During the Company's two most recent fiscal years, there were no disagreements with Andersen on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Andersen, would have caused Andersen to make reference to the subject matter of the disagreements in connection with Andersen's report; and during such period there were no "reportable events" of the kind listed in Item 304(a)(1)(v) of Regulation S-K.

The Company disclosed the foregoing information on a Current Report on Form 8-K dated May 3, 2002 (the "Form 8-K"). The Company provided Andersen with a copy of the foregoing disclosure and requested Andersen to furnish the Company with a letter addressed to the Securities and Exchange Commission stating whether Andersen agreed with the statements by the Company in the foregoing disclosure and, if not, stating the respects in which it did not agree. Andersen's letter stated that it had read the pertinent paragraphs of the Form 8-K and was in agreement with the statements contained therein. Andersen's letter is incorporated herein by reference to Exhibit 16.1 of the Form 8-K.

During the Company's two most recent fiscal years and through the date of this Annual Report on Form 10-K, the Company did not consult KPMG with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's consolidated financial statements, or any other matters or reportable events listed in Items 304(a)(2)(i) and (ii) of Regulation S-K.

PART III

Items 10, 11, 12 and 13 ⇒ Directors and Executive Officers of the Company, Executive Compensation, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Certain Relationships and Related Transactions

Except for information concerning executive officers of the Company included as an unnumbered item in Part I hereof, in accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this report.

Item 14 ⇒ Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures:

Within the 90 day period prior to the filing date of this Annual Report on Form 10-K, the Company, under the supervision, and with the participation, of its management, including its principal executive officer and principal financial officer, performed an evaluation of the design and operation of the Company's disclosure controls and procedures (as defined in Securities and Exchange Act Rule 13a-14(c)). Based on that evaluation, the Company's principal executive officer and principal financial officer concluded that such disclosure controls and procedures are effective to ensure that material information relating to the Company, including its consolidated subsidiaries, is accumulated and communicated to the Company's management and made known to the principal executive officer and principal financial officer, particularly during the period for which this periodic report was being prepared.

(b) Changes in Internal Controls

No significant changes were made in the Company's internal controls or in other factors that could significantly affect these controls subsequent to the date of the evaluation described in Item 14 (a).

PART IV

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

(a) Financial Statements

1. Financial Statements – The financial statements filed herewith are listed in the Index to Financial Statements on page 36 of this report.

2. All schedules are omitted because they are not required, inapplicable or the information is included in the consolidated financial statements or the notes thereto.

3. Exhibits

(3.1) Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.2) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.3) Amended bylaws of Registrant (incorporated by reference to Exhibit 3.1 to Registrant's Report on Form 8-K filed on March 28, 2002).

(4.1) Rights Agreement dated as of February 11, 1998 between Penn Virginia Corporation and American Stock Transfer & Trust Company, as Agent (incorporated by reference to Exhibit 1.1 to Registrant's Registration Statement on Form 8-A filed on February 20, 1998).

(4.2) Amendment No. 1 to Rights Agreement dated March 27, 2002 by and between Penn Virginia Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.1 of Registrant's Report on Form 8-K filed on March 28, 2002).

(10.1) Credit Agreement dated as of October 30, 2001 among Penn Virginia Corporation, the lenders party thereto, First Union National Bank, Bank One, NA, and Royal Bank of Canada, as Co-Syndication Agents, and The Chase Manhattan Bank, as Administrative Agent (incorporated by reference to Exhibit 10.1 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2001).

(10.2) Penn Virginia Corporation and Affiliated Companies Employees' Stock Ownership Plan, as amended (incorporated by reference to Exhibit 10.2 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2001).

(10.3) Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan, as amended (incorporated by reference to Exhibit 10.3 of Registrant's Annual Report on Form 10-K for the year ended December 31, 2001).

(10.6) Penn Virginia Corporation 1995 Third Amended and Restated Directors' Stock Compensation Plan.

(10.7) Penn Virginia Corporation Amended 1999 Employee Stock Incentive Plan.

(10.8) Omnibus Agreement ("Omnibus Agreement") dated October 30, 2001 among Penn Virginia Corporation, Penn Virginia Resource GP, LLC, Penn Virginia Operating Co., LLC and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.2 to Registrant's Report on Form 8-K filed on November 14, 2001).

(10.9) Amendment No. 1 to Omnibus Agreement.

(10.10) Penn Virginia Corporation 1994 Stock Option Plan, as amended (incorporated by reference to Exhibit 10.5 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(10.11) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and A. James Dearlove (incorporated by reference to Exhibit 10.1 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.12) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and Frank A. Pici (incorporated by reference to Exhibit 10.2 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.13) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.14) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(10.15) Change of Control Severance Agreement dated May 7, 2002 between Penn Virginia Corporation and Keith D. Horton (incorporated by reference to Exhibit 10.5 of Registrant's Report on Form 10-Q for the period ended March 31, 2002).

(21) Subsidiaries of Registrant.

(23.1) Consent of KPMG LLP.

(99.1) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(99.2) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K

On October 30, 2002, Registrant filed a report on Form 8-K. The report involved the resignation of a director of Registrant's Board of Directors.

On December 6, 2002, Registrant filed a report on Form 8-K. The report involved the election of a director to Registrant's Board of Directors.

Corporate Information

Directors

Robert Garrett[1,2]
Chairman of the Board of the Company and President of AdMedia Partners, Inc.

Edward B. Cloues, II[2,3]
Chairman and Chief Executive Officer of K-Tron International, Inc.

A. James Dearlove
President and Chief Executive Officer of the Company and Chairman and Chief Executive Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

H. Jarrell Gibbs[1,3]
Former President and Vice Chairman of TXU Corp.

Keith D. Horton
Executive Vice President of the Company and President and Chief Operating Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

Marsha Reines Perelman[1,3,4]
Chief Executive Officer of Woodforde Management, Inc.

Joe T. Rye[1,3,4]
President of Joe T. Rye, P.C., former President and Chief Executive Officer of Universal Seismic Associates, Inc. and former Senior Vice President and Chief Financial Officer of Seagull Energy Corporation

Gary K. Wright[2,4]
Independent Consultant, former Southwest Managing Director for Chase Manhattan Bank Global Oil and Gas Group and former Manager of Chemical Bank Worldwide Energy Group

1 Member of the Nominating Committee
2 Member of the Compensation & Benefits Committee
3 Member of the Audit Committee
4 Member of the Oil and Gas Committee

Management

A. James Dearlove
President and Chief Executive Officer

Frank A. Pici
Executive Vice President and Chief Financial Officer

H. Baird Whitehead
Executive Vice President

Keith D. Horton
Executive Vice President

Nancy M. Snyder
Senior Vice President, General Counsel and Corporate Secretary

Dana G. Wright
Vice President and Controller

Major Subsidiaries

Penn Virginia Oil and Gas Corporation
Penn Virginia Resource GP, LLC

Annual Meeting

Penn Virginia Corporation's Annual Meeting will be held 10 a.m. May 6, 2003 at
Marriott Philadelphia West
111 Crawford Avenue
West Conshohocken, PA 19428
Telephone: (610) 941-5600
Facsimile: (610) 941-1060

Transfer Agent & Registrar

American Stock Transfer & Trust Company
Mailing Address:
59 Maiden Lane
New York, NY 10038
Telephone: (800) 937-5449
Facsimile: (718) 236-2641

Penn Virginia Corporation

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