UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2005

Commission File Number: 0-753

Penn Virginia Corporation

(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

Three Radnor Corporate Center, Suite 300
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

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

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, $0.01 Par Value	New York Stock Exchange

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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 ☒ 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. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check One)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of common stock held by non-affiliates of the registrant was $818,538,083 as of June 30, 2005 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and all executive officers, but excluding any institutional shareholders. This determination is not necessarily a conclusive determination for other purposes.

As of March 8, 2006, 18,644,728 shares of common stock of the registrant were issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

	Part Into Which Incorporated
(1) Proxy Statement for Annual Meeting of Shareholders on May 2, 2006	Part III

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

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PART I

Item 1 *Business*

General

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is a Virginia corporation founded in 1882 whose common stock is traded on the New York Stock Exchange under the symbol "PVA." We are engaged in the exploration, development and production of crude oil and natural gas primarily in the Appalachian, Mississippi, east Texas 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, 2005, we had proved reserves of approximately 2.9 million barrels of oil and condensate and 359 billion cubic feet ("Bcf") of natural gas, or 377 billion cubic feet equivalent ("Bcfe").

We are also indirectly involved in the businesses engaged in by Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), a Delaware limited partnership whose common units are traded on the New York Stock Exchange under the symbol "PVR." Our wholly owned subsidiary, Penn Virginia Resource GP, LLC, a Delaware limited liability company, serves as the general partner of the Partnership. As of December 31, 2005, we owned approximately 39 percent of the Partnership, consisting of a two percent general partner interest and a 37 percent limited partner interest. 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 the Partnership's quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. See Item 1, "Business—Partnership Distributions," for more information on incentive distribution rights.

PVR conducts operations in two business segments: coal and natural gas midstream. The Partnership does not operate any coal mines, but rather leases its coal reserves to various mining operators in exchange for royalty payments. Additionally, the Partnership provides fee-based coal preparation and loading facilities to some of its lessees and to other third party industrial end-users. On March 3, 2005, the Partnership acquired a midstream gas gathering and processing business with primary locations in the mid-continent area of Oklahoma and the Texas panhandle from Cantera Natural Gas, LLC. For a further discussion of this acquisition, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments."

Financial Information and Segments

We operate in three primary business segments. We are in the crude oil and natural gas exploration and production business and, through our interests in PVR, we are in the coal and natural gas midstream businesses. 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. In 2005, approximately 59 percent of our operating income was attributable to our oil and gas segment, 38 percent was attributable to our coal segment and 10 percent was attributable to our natural gas midstream segment, less a seven percent operating loss related to corporate and other functions. See Note 21 in the Notes to Consolidated Financial Statements for financial information concerning our business segments.

Oil and Gas Segment Overview

General

In our oil and gas segment, our goal is to use our knowledge and experience to build a portfolio of assets with sustainability and growth potential, even at much lower commodity prices than we experienced in 2005. We focus on relatively low risk, unconventional natural gas-oriented resource plays, such as our horizontal coal bed methane ("HCBM") project in Appalachia, our Cotton Valley play in east Texas and north Louisiana and our Selma Chalk project in Mississippi. We are also assessing the potential of organic shale plays in the Appalachian and Illinois Basins and new unconventional plays in the Williston Basin. We also generate and drill exploratory prospects which could make a meaningful difference to our production and reserve profile, primarily in south Texas and south Louisiana.

Our increased oil and gas segment operating income and cash flows in 2005 were the direct result of both our record oil and natural gas production levels and price realizations. Highlights of our oil and gas segment's performance in 2005 are as follows:

- Oil and gas production in 2005 was 27.4 Bcfe, a Company record. This production increase, which surpassed the previous record of 24.5 Bcfe in 2004 by 12 percent, was primarily due to the continued success of our development projects in Appalachia, east Texas and Mississippi.
- Our estimated proved reserves at the end of 2005 were a Company record 377 Bcfe, up six percent from 354 Bcfe at the end of 2004, and up 14 percent after considering our sale of 27 Bcfe in the first quarter of 2005. Natural gas comprised approximately 93 percent of year-end 2005 proved reserves, and 74 percent of total year-end reserves were attributable to proved developed wells. Net of revisions, we added approximately 77 Bcfe of proved reserves primarily from extensions, discoveries and additions, replacing 281 percent of 2005 production.
- We drilled 178 wells during 2005, including 166 development wells and 12 exploratory wells. All but three of the development wells were successful. Six of the exploratory wells were successful, three were dry holes, and three are under evaluation.

In 2005, we drilled 23 development wells in our HCBM project in West Virginia. All were successful. Net production from our HCBM wells increased 125 percent, from 2.7 Bcfe in 2004 to approximately 6.1 Bcfe in 2005. We also added approximately 60,000 acres to our CBM-prospective leasehold position in the Appalachian Basin and modified our agreement with CDX Gas, LLC ("CDX") to obligate CDX to commit three horizontal drilling rigs and associated crews to drill full-time within our area of mutual interest with CDX, which covers most of central Appalachia.

We drilled 28 development wells in our Cotton Valley project in east Texas and north Louisiana. Again, all were successful. Most of these wells were in the North Carthage field, which is part of our Bethany development drilling joint venture with GMX Resources Inc. (NASDAQ: GMXR). As a direct result of our successful and growing development drilling program in the play, net production in the Cotton Valley project area increased to 2.7 Bcfe in 2005 from 1.1 Bcfe in 2004.

We drilled 85 successful development wells in our Selma Chalk project in Mississippi during 2005. Production in our Mississippi fields in 2005 was 5.4 Bcfe, compared to 4.9 Bcfe in 2004. This increase was primarily a result of new production in the Baxterville and Maxie fields, offset in part by normal field declines and disruptions due to Hurricane Katrina.

In south Texas and south Louisiana, we drilled five exploratory wells with three successes and four development wells, three of which were successful, including a successful Lower Frio exploratory well and follow-on development well drilled in our Estill prospect in the Rugeley field in Matagorda County, Texas. The prospect was generated by us, with a 50 percent working interest, and is operated by Brigham Exploration Company (NASDAQ: BEXP). Another successful exploratory well was drilled in the Hackberry formation on our Fannett prospect in Jefferson County, Texas, in which we have a 60 percent working interest.

During 2005, we also began evaluating several new potential development plays. In the Williston Basin, we drilled an exploratory well as part of our agreement with Bill Barrett Corporation (NYSE: BBG) for a 50 percent working interest in a 20,000 net acre Bakken Dolomite horizontal oil well prospect. We also drilled two 100 percent working interest exploratory wells in the New Albany Shale in the Illinois Basin during the fourth quarter. Reservoir analysis is currently in progress, with completion and testing expected over the remainder of 2006.

Transportation

The majority of our natural gas production is transported to market on four major pipeline or transmission systems. NiSource Inc., Crosstex Energy Services L.P., Gulf South Pipeline Company, LP, and Dominion Transmission, Inc., transported 31 percent, 19 percent, 14 percent and 12 percent of our 2005 natural gas production. The remainder of our natural gas production was transported by several pipeline companies in Texas, Louisiana and West Virginia. In almost all cases, our natural gas is sold at interconnects with transmission pipelines.

We have entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 10 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Marketing and Hedging

We generally sell our natural gas using spot market and short-term fixed price physical contracts. For the year ended December 31, 2005, two customers of the oil and gas segment, Dominion Field Services and Crosstex Gulfcoast Marketing, accounted for approximately 29 percent and 25 percent of our natural gas and oil and condensate revenues of $226.2 million.

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 and crude oil 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 losses on settled hedging activities of $14.9 million, $5.9 million and $6.1 million in 2005, 2004 and 2003. In 2005, we hedged approximately 42 percent of our natural gas production using costless collars at an average floor price of $ 5.61 per MMbtu and an average ceiling price of $8.10 per MMbtu. We also hedged approximately 31 percent of our crude oil production using a fixed price swap in January 2005 and a costless collar beginning in March 2005 and continuing for the remainder of the year. The swap price was $30.59 per barrel, and the costless collar had a floor price of $42.00 per barrel and a ceiling price of $47.75 per barrel. See Note 11 in the Notes to Consolidated Financial Statements for information about our price risk management positions for future periods.

Coal Segment Overview

In our coal segment, PVR owned or controlled approximately 689 million tons of coal as of December 31, 2005. PVR enters into long-term leases with experienced, third-party mine operators providing them the right to mine PVR's coal reserves in exchange for royalty payments. PVR does not operate any mines. In 2005, PVR's lessees produced 30.2 million tons of coal from its properties and paid PVR coal royalty revenues of $82.7 million, for an average gross coal royalty per ton of $2.74. Approximately 83 percent of coal royalty revenues in 2005 and 79 percent of coal royalty revenues in 2004 were derived from coal mined on PVR's properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of coal royalty revenues for the respective periods was derived from coal mined on PVR's properties under leases containing fixed royalty rates which escalate annually. Substantially all of PVR's leases require the lessee to pay minimum rental payments in monthly or annual installments. PVR actively works with its lessees to develop efficient methods to exploit coal reserves and to maximize production from PVR's properties. PVR earns revenues from providing fee-based coal preparation and transportation services to PVR's lessees, which enhance their production levels and generate additional coal royalty revenues, and from industrial third party coal end-users by owning and operating coal handling facilities through PVR's joint venture with Massey Energy Company ("Massey"). PVR also earns revenues from oil and gas royalty interests, coal transportation ("wheelage") rights and the sale of standing timber on PVR's properties.

PVR's management continues to focus on acquisitions which increase and diversify PVR's sources of cash flow. PVR completed four coal reserve acquisitions in 2005, spending approximately $101 million to add approximately 162 million tons of coal reserves, including 94 million tons of coal reserves in the Illinois Basin, a new area for PVR. PVR's 2005 acquisitions also included oil and natural gas well royalty interests and wheelage rights. For a more detailed discussion of PVR's acquisitions, see Item 7, "Managements' Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments."

Natural Gas Midstream Segment Overview

On March 3, 2005, PVR completed the acquisition of Cantera Gas Resources, LLC ("Cantera"), a midstream gas gathering and processing company with primary locations in the mid-continent area of Oklahoma and the panhandle of Texas (the "Cantera Acquisition"). As a result of the Cantera Acquisition, PVR owns and operates a significant set of midstream assets that include approximately 3,450 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 million cubic feet per day (MMcfd) of total capacity. PVR's midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. The Cantera Acquisition also included a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. PVR believes that the Cantera Acquisition established a platform for future growth in the natural gas midstream sector and diversified its cash flows into another long-lived asset base. Since acquiring this business, PVR has focused on integrating the accounting and commercial systems necessary to prudently operating a natural gas midstream business, and has expanded its natural gas midstream business by adding 27 miles of new gathering lines which connect 92 new wells to PVR's gathering and processing systems.

For the ten months ended December 31, 2005, PVR's midstream operations generated a gross processing margin of $44.7 million, consisting of midstream revenues minus the cost of gas purchased. Inlet volumes at PVR's gas processing plants and gathering systems were 38.9 Bcf, or approximately 127 MMcfd, for the same ten-month period, with a gross processing margin of $1.15 per thousand cubic feet (Mcf). Two of PVR's natural gas midstream customers, BP Canada Energy Marketing Corp. and ConocoPhillips Company, accounted for 12 percent and 11 percent of our consolidated revenues in 2005.

PVR continually seeks new supplies of natural gas to both offset the natural declines in production from the wells currently connected to its systems and to increase throughput volume. New natural gas supplies are obtained for all of PVR's systems by contracting for production from new wells, connecting new wells drilled on dedicated acreage and by contracting for natural gas that has been released from competitors' systems.

Business Strategy

Our principal business strategies for the oil and gas segment, the coal segment, the natural gas midstream segment and the Company in general are:

- Oil and gas segment
  - Focus on relatively low risk, unconventional natural gas-oriented resource plays, such as the HCBM play in Appalachia, the Cotton Valley play in east Texas and north Louisiana and the Selma Chalk in Mississippi. In addition to our established core areas, we are assessing the potential to establish new sustainable growth in organic shale and other unconventional plays in new areas, such as the Williston and Illinois Basins. We work with established industry partners in several of these core and potential new areas.
  - Generate and drill exploratory prospects, primarily in south Texas and south Louisiana, which could result in an increase in our proved reserves and production. These prospects tend to have relatively higher risk profiles and higher returns when successful, and we work with industry partners to better manage costs and risks.
- Coal segment (PVR Coal)
  - Continue to acquire coal reserves, including in PVR's Appalachian core area and new areas. For example, PVR's 2005 acquisition of 94 million tons of Illinois Basin coal reserves was made because PVR views the Illinois Basin as a growth area, both because of its proximity to power plants and because it expects future environmental regulations will require scrubbing of most coals, including lower sulfur coals from other basins.
  - Expand PVR's coal services and infrastructure business on PVR's properties and PVR's joint venture with Massey, which provides coal handling facilities and services to industrial end users.
- Natural gas midstream segment (PVR Midstream)
  - Expand PVR Midstream, both organically, by adding new natural gas production to PVR's existing gathering and processing systems, and through acquisitions of new stand-alone midstream assets or those which can be assimilated into PVR's existing systems.
  - Explore ways for PVR to provide services to our oil and gas exploration and production business.
- Company
  - Maintain financial discipline and flexibility. The Company and PVR operate with separate, independent capital structures. We intend to continue to be fiscally conservative in both entities and to manage our capital structure for the long term, which means that we will continue to be cautious regarding debt levels and dividend or distribution increases.

Partnership Distributions

Cash Distributions

The Partnership paid cash distributions of $2.4825 per common and subordinated unit during the year ended December 31, 2005. In the first quarter of 2006, the Partnership paid a quarterly distribution of $0.70 ($2.80 annualized) per unit with respect to the fourth quarter of 2005. For the remainder of 2006, the Partnership expects to pay quarterly distributions of $0.70 ($2.80 annualized) or more per common and subordinated unit.

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 the two percent general partner interest and the incentive distribution rights held by our general partner subsidiary. We received total distributions from PVR of $21.2 million and $17.3 million in 2005 and 2004, as shown in the following table (in thousands):

	2005	2004
Limited partner units	$ 19,281	$ 16,511
General partner interest (2%)	1,021	788
Incentive distribution rights	910	—
Total	$ 21,212	$ 17,299

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 annualized). Our general partner subsidiary currently holds 100 percent of the incentive distribution rights, but may transfer these rights separately from its general partner interest to an affiliate (other than an individual) or to another entity as part of the merger or consolidation of the general partner with or into such entity or the transfer of all or substantially all of the general partner's assets to another entity without the prior approval of PVR's unitholders if the transferee agrees to be bound by the provisions of PVR's partnership agreement. Prior to September 30, 2011, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of PVR's outstanding common units and subordinated units, voting as separate classes. On or after September 30, 2011, the incentive distribution rights will be freely transferable. 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, and two 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.

Subordination Period

During the subordination period, which we describe below, PVR's common units have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution, plus arrearages in the payment of any minimum quarterly distribution from prior quarters, before any distributions of available cash from operating surplus can be made on the subordinated units. Our wholly owned subsidiaries currently own an aggregate 3,824,940 subordinated units. These subordinated units will convert to common units after the events described below have occurred.

The subordination period began on October 30, 2001, and will continue until the first day of the first quarter beginning after September 30, 2006, on which each of the following events has occurred:

- distributions of available cash from operating surplus on each of the common units and the subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the adjusted operating surplus generated during each of the three immediately preceding, non-overlapping four-quarter periods equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the two percent general partner interest during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Competition

Oil and Gas

The oil and natural gas industry is very competitive, and we compete with a substantial number of other companies that are large, well-established and have greater financial and operational resources than we do, which may adversely affect our ability to compete or grow our business. 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. 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 other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells and recruiting and retaining qualified personnel, including geologists, geo-physicists, engineers and other specialists. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. 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.

Coal

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. PVR's lessees compete with coal producers in various regions of the United States for domestic sales. The industry has undergone significant consolidation which has led to some of the competitors of PVR's lessees having significantly larger financial and operating resources than most of PVR's lessees. PVR's lessees primarily compete with both large and small producers in Appalachia as well as in the western United States. PVR's lessees 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 PVR's coal and the prices that PVR's lessees obtain are also affected by demand for electricity, demand for metallurgical coal, access to transportation, 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 PVR's low sulfur coal and the prices PVR'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 which permit the high sulfur coal to meet federal Clean Air Act requirements.

Natural Gas Midstream

The ability to offer natural gas producers competitive gathering and processing arrangements and subsequent reliable service is fundamental to obtaining and keeping gas supplies for PVR's gathering systems. The primary concerns of the producer are:

- the pressure maintained on the system at the point of receipt;
- the relative volumes of gas consumed as fuel and lost;
- the gathering/processing fees charged;
- the timeliness of well connects;
- the customer service orientation of the gatherer/processor; and
- the reliability of the field services provided.

PVR experiences competition in all of its midstream markets. PVR's competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of PVR's competitors have greater financial resources and access to larger natural gas supplies than PVR does.

Regulation

Oil and Gas

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 permitting regulations regarding the drilling of wells, maintaining bonding requirements in order to drill or operate wells, locating 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 (the "FERC") regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 (the "NGA") and the Natural Gas Policy Act of 1978 (the "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 their own natural gas production 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' sale 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 us, 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 Nos. 637, 637-A and 637-B which, among other things, (i) permit pipelines to charge different maximum cost-based rates for peak and off-peak periods, (ii) encourage auctions for pipeline capacity, (iii) require pipelines to implement imbalance management services and (iv) restrict the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders. In addition, the FERC has regulations in place that govern the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement establishing a presumption in favor of requiring owners of newly constructed pipeline facilities to charge rates based on the incremental 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 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.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens

Coal

General Regulation Applicable to Coal Lessees. PVR'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 ("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 PVR's lessees can be eliminated completely. However, none of the violations to date, or the monetary penalties assessed, have been material to us, PVR or, to our knowledge, to PVR's lessees. PVR does not currently expect that future compliance will have a material adverse effect on PVR.

While it is not possible to quantify the costs of compliance by PVR's lessees with all applicable federal, state and local laws and regulations, 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. We do not accrue for such costs because PVR's lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, PVR does require some smaller lessees to deposit into escrow certain funds 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 and regulations 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 coal mined by PVR's lessees. The possibility exists that new legislation or regulations may be adopted which have a significant impact on the mining operations of PVR's lessees or their customers' ability to use coal and may require PVR, its lessees or their customers to change operations significantly or incur substantial costs.

Air Emissions. The federal Clean Air Act and corresponding state and local laws and regulations affect all aspects of PVR's business. The Clean Air Act directly impacts PVR's lessees' coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of recent federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and additional measures required under U.S. Environmental Protection Agency ("EPA") laws and regulations will make it more costly to operate coal-fired power plants and, depending on the requirements of individual state implementation plans, could make coal a less attractive fuel alternative in the planning and building of power plants in the future. Any reduction in coal's share of power generating capacity could negatively impact PVR's lessees' ability to sell coal, which could have a material effect on PVR's coal royalty revenues.

The EPA's Acid Rain Program, provided in Title IV of the Clean Air Act, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels.

The EPA has promulgated rules, referred to as the "NOx SIP Call," that require coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule ("CAIR"), which will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C beginning in 2009 and 2010, respectively. CAIR requires these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered "cap-and-trade" program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state.

In March 2005, the EPA finalized the Clean Air Mercury Rule ("CAMR"), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. While currently the subject of extensive controversy and litigation, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

The EPA has adopted new, more stringent national air quality standards for ozone and fine particulate matter. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. For example, in December 2004, the EPA designated specific areas in the United States as in "non-attainment" with the new national ambient air quality standard for fine particulate matter. In November 2005, the EPA published proposed rules addressing how states would implement plans to bring applicable non-attainment regions into compliance with the new air quality standard. Under the EPA's proposed rulemaking, states would have until April 2008 to submit their implementation plans to the EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, PVR's lessees' mining operations and their customers could be affected when the new standards are implemented by the applicable states.

In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. As part of the new rules, affected states must develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide and particulate matter.

The U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the new source review provisions of the Clean Air Act. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for PVR's coal could be affected, which could have an adverse effect on PVR's coal royalty revenues.

Carbon Dioxide Emissions. The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to five percent below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty.

In 2002, the United States withdrew its support for the Kyoto Protocol. As the Kyoto Protocol becomes effective, there will likely be increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. The United States Congress has considered bills in the past that would regulate domestic carbon dioxide emissions, but such bills have not yet received sufficient Congressional support for passage into law. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program to stabilize carbon dioxide emissions from regional power plants beginning in 2009.

It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact PVR's lessees' coal sales, and thereby have an adverse affect on PVR's coal royalty revenues.

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 and 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 PVR's coal lessees to it if any of those lessees are not financially capable of fulfilling those obligations. In conjunction with mining the property, PVR's coal lessees are contractually obligated under the terms of their leases to comply with all state and local laws, including SMCRA, with obligations including the reclamation and restoration of 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.

Hazardous Materials and Wastes. The Federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or the "Superfund" law), and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Some products used by coal companies in operations generate waste containing hazardous substances. PVR could become liable under federal and state Superfund and waste management statutes if PVR's lessees are unable to pay environmental cleanup costs. CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek recovery from the responsible classes of persons the costs they incurred in connection with such response. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment.

Water Discharges. PVR's coal lessees' operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States or state waters. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit.

PVR's lessees' mining operations are strictly regulated by the Clean Water Act, particularly with respect to the discharge of overburden and fill material into jurisdictional waters, including wetlands. Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. While the decision was vacated by the Fourth Circuit Court of Appeals in November 2005, a similar lawsuit has been filed in federal district court in Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. In the event similar lawsuits prove to be successful in adjoining jurisdictions, PVR's lessees may be required to apply for individual discharge permits pursuant to Section 404 of the Clean Water Act in areas where they would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in PVR's lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on PVR's coal royalty revenues.

The Clean Water Act also requires states to develop anti-degradation policies to ensure non-impaired waterbodies in the state do not fall below applicable water quality standards. These and other regulatory developments may restrict PVR's lessees' ability to develop new mines or could require its lessees to modify existing operations, which could have an adverse effect on PVR's coal business.

The Federal Safe Drinking Water Act ("SDWA") and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of "public water systems." This regulatory program could impact PVR's lessees' reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners.

Mine Health and Safety Laws. The operations of PVR's lessees are subject to stringent health and safety standards that 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 health and safety 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 or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that are likely to result in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. These recent events could also potentially result in the promulgation of more stringent mine safety laws and regulations, or amendments to existing mine safety laws, including increased sanctions for non-compliance. These potential future mine safety laws and regulations, or amendments to existing mine safety laws, and the cost of compliance with such, could adversely affect PVR's lessees' coal production, which could have an adverse affect on PVR's coal royalty revenues.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, PVR'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 PVR'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, PVR's lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In PVR's experience, permits generally are approved within 12 months after a completed application is submitted. In the past, PVR's lessees have generally obtained their mining permits without significant delay. PVR's lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined over the next five years. PVR's lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, there are no assurances that they will not experience difficulty in obtaining mining permits in the future. See Item 1, "Business—Regulation—Coal—Water Discharges."

OSHA. PVR's lessees and its own business are subject to OSHA. See Item 1, "Business—Regulation—Oil and Gas—OSHA."

Natural Gas Midstream

General Regulation. The Partnership's natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but FERC regulation nevertheless could significantly affect its gathering business and the market for its services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which the Partnership's gathering pipelines deliver. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

In Texas, the Partnership's gathering facilities are subject to regulation by the Texas Railroad Commission, which has the authority to ensure that rates, terms and conditions of gas utilities, including certain gathering facilities, are just and reasonable and not discriminatory. The Partnership's operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits it from charging any unduly discriminatory fees for its gathering services. We cannot predict whether the Partnership's gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

The Partnership is subject to ratable take and common purchaser statutes in Texas and Oklahoma. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting the Partnership's right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and Texas and Oklahoma have adopted complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. We cannot assure you that federal and state authorities will retain their current regulatory policies in the future.

Texas and Oklahoma administer federal pipeline safety standards under the NGPSA, which requires certain pipelines to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. In response to recent pipeline accidents, Congress and the U.S. Department of Transportation have recently instituted heightened pipeline safety requirements. Certain of the Partnership's gathering facilities are exempt from these federal pipeline safety requirements under the rural gathering exemption. We cannot assure you that the rural gathering exemption will be retained in its current form in the future.

Failure to comply with applicable regulations under the NGA, the NGPSA and certain state laws can result in the imposition of administrative, civil and criminal remedies.

Air Emissions. PVR's midstream operations are subject to the Clean Air Act and comparable state laws and regulations. See Item 1, "Business—Regulation—Coal—Air Emissions." These laws and regulations govern emissions of pollutants into the air resulting from the activities of PVR's processing plants and compressor stations and also impose procedural requirements on how PVR conducts its midstream operations. Such laws and regulations may include requirements that PVR obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, strictly comply with the emissions and operational limitations of air emissions permits PVR is required to obtain or utilize specific equipment or technologies to control emissions. PVR's failure to comply with these requirements could subject PVR to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. PVR will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Hazardous Materials and Wastes. PVR's midstream operations could incur liability under CERCLA and comparable state laws resulting from the disposal or other release of hazardous substances or wastes originating from properties PVR owns or operates, regardless of whether such disposal or release occurred during or prior to PVR's acquisition of such properties. See Item 1, "Business—Regulation—Coal—Hazardous Materials and Waste." Although petroleum, including natural gas and NGLs are generally excluded from CERCLA's definition of "hazardous substance," PVR's midstream operations do generate wastes in the course of ordinary operations that may fall within the definition of a "hazardous substance."

PVR's midstream operations generate wastes, including some hazardous wastes, that are subject to the Resource Conservation and Recovery Act ("RCRA") and comparable state laws. However, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. Unrecovered petroleum product wastes, however, may still be regulated under RCRA as solid waste. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas and NGLs in pipelines may also generate some hazardous wastes. Although we believe it is unlikely that the RCRA exemption will be repealed in the near future, repeal would increase costs for waste disposal and environmental remediation at PVR's facilities.

PVR currently owns or leases numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although we believe that the operators of such properties used operating and disposal practices that were standard in the industry at the time, hydrocarbons or wastes may have been disposed of or released on or under such properties or on or under other locations where such wastes have been taken for disposal. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, PVR could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination, whether from prior owners or operators or other historic activities or spills) or to perform remedial plugging or pit closure operations to prevent future contamination. PVR has ongoing remediation projects underway at several sites, but it does not believe that the costs associated with such cleanups will have a material adverse impact on PVR's operations or revenues.

Water Discharges. PVR's midstream operations are subject to the Clean Water Act. See Item 1, "Business—Regulation—Coal—Water Discharges." Any unpermitted release of pollutants, including NGLs or condensates, from PVR's systems or facilities could result in fines or penalties as well as significant remedial obligations.

OSHA. PVR Midstream's operations are subject to OSHA. See Item 1, "Business—Regulation—Coal—OSHA."

Employees and Labor Relations

We and our subsidiaries had a total of 229 employees at December 31, 2005, including 111 employees who directly provide services for PVR through its general partner. We consider our current employee relations to be favorable.

Available Information

The Company's Internet address is www.pennvirginia.com. We make available free of charge on or through our Internet website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics and the charters of each of our Audit Committee, Nominating and Governance Committee, Compensation and Benefits Committee and Oil and Gas Committee, and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our Internet website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (the "SEC").

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	58	President and Chief Executive Officer
Keith D. Horton	52	Executive Vice President
Ronald K. Page	55	Vice President
Frank A. Pici	50	Executive Vice President and Chief Financial Officer
Nancy M. Snyder	53	Senior Vice President, General Counsel and Corporate Secretary
H. Baird Whitehead	55	Executive Vice President

A. James Dearlove has served in various capacities with the Company since 1977, including as President and Chief Executive Officer since May 1996 and as a director since February 1996, as President and Chief Operating Officer from 1994 to May 1996, as Senior Vice President from 1992 to 1994 and as Vice President from 1986 to 1992. Mr. Dearlove has also served as Chief Executive Officer and Chairman of the Board of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P. since July 2001 and December 2002. Mr. Dearlove also serves as a director of the National Council of Coal Lessors.

Keith D. Horton has served in various capacities with the Company since 1981, including as Executive Vice President and director since December 2000, as Vice President—Eastern Operations from February 1999 to December 2000, as Vice President from February 1996 to February 1999, as President of Penn Virginia Coal Company from February 1996 to October 2001, as Vice President of Penn Virginia Coal Company from March 1994 to February 1996, as Vice President of Penn Virginia Resources Corporation from January 1990 to December 1998 and as Manager, Coal Operations of Penn Virginia Resources Corporation from July 1982 to December 1989. Mr. Horton has also served as President and Chief Operating Officer of Penn Virginia Resource GP, LLC since July 2001. Mr. Horton serves as a director of the Virginia Mining Association, the Powell River Project and the Eastern Coal Council.

Ronald K. Page has served in various capacities with the Company since July 2001, including as Vice President since May 2005 and as Vice President, Corporate Development from July 2003 to May 2005. Mr. Page has also served as Vice President, Corporate Development of Penn Virginia Resource GP, LLC since July 2003 and President of PVR Midstream LLC since January 2005. From January 1998 to May 2003, Mr. Page served in various positions with El Paso Field Services Company, including as Vice President of Commercial Operations—Texas Pipelines and Processing, Vice President of Business Development and Director of Business Development. From October 1995 through December 1997, Mr. Page served as Vice President of Business Development of TPC Corporation (formerly Texas Power Corporation). For 17 years prior to 1995, Mr. Page served in various positions at Seagull Energy Corporation, including as Vice President of Operations at Seagull's Enstar Natural Gas Company, Vice President of Pipelines and Marketing and Manager of Engineering.

Frank A. Pici has served as Executive Vice President and Chief Financial Officer of the Company since September 2001. Mr. Pici has also served as Vice President and Chief Financial Officer and as a director of Penn Virginia Resource GP, LLC since September 2001 and October 2002. From 1996 to 2001, Mr. Pici served as Vice President—Finance and Chief

Financial Officer of Mariner Energy, Inc. ("Mariner"), an oil and gas exploration and production company, where he managed all financial aspects of Mariner, including accounting, tax, finance, banking, investor relations, planning and budgeting and information technology. Prior to 1996, Mr. Pici served in various capacities with Cabot Oil & Gas Corporation ("Cabot"), including Corporate Controller from 1994 to 1996, Director, Internal Audit from 1992 to 1994 and Region Accounting Manager from 1989 to 1992. Mr. Pici served as Controller for Doran Associates, Inc., an oil and gas exploration and production company, from 1984 to 1989.

Nancy M. Snyder has served in various capacities with the Company since 1997, including as Senior Vice President since February 2003, as Vice President from December 2000 to February 2003 and as General Counsel and Corporate Secretary since 1997. Ms. Snyder has also served as Vice President and General Counsel and as a director of Penn Virginia Resource GP, LLC since July 2001. 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 women's retail fashion and real estate. From 1983 to 1989, Ms. Snyder was an associate at the law firm of Duane Morris LLP, where she practiced securities, banking and general corporate law.

H. Baird Whitehead has served as Executive Vice President of the Company since January 2001 and as President of Penn Virginia Oil & Gas Corporation since January 2001. Prior to joining Penn Virginia, Mr. Whitehead served in various positions with Cabot. From 1998 to 2001, Mr. Whitehead 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 Texas and Louisiana Gulf Coast areas. From 1992 to 1998, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Appalachian business unit. From 1989 to 1992, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Anadarko business unit. From 1987 to 1989, Mr. Whitehead served as Vice President of Engineering for Cabot. From 1972 to 1987, Mr. Whitehead held various engineering and supervisory positions with Texaco, Columbia Gas Transmission and Cabot.

Common Abbreviations and Definitions

The following terms have the meanings indicated below when used in this Annual Report on Form 10-K.

Bbl—	a standard barrel of 42 U.S. gallons liquid volume
Bcf—	one billion cubic feet
Bcfe—	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
CBM—	coalbed methane
Developed acreage—	lease acreage that is allocated or assignable to producing wells or wells capable of production
Development well—	a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive
Dry hole—	a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion of the well
Exploratory or exploration well—	a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir
Gross acre or well—	an acre or well in which a working interest is owned
Mbbl—	one thousand barrels
Mbf—	one thousand board feet
Mcf—	one thousand cubic feet
Mcfe—	one thousand cubic feet equivalent
MMbbl—	one million barrels
MMbf—	one million board feet

MMbtu—	one million British thermal units
MMcf—	one million cubic feet
MMcfe—	one million cubic feet equivalent
Net acre or well—	gross acres or wells multiplied by the owned working interest in those gross acres or wells
NGL—	natural gas liquid
NYMEX—	New York Mercantile Exchange
Present value of proved reserves—	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—	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
Productive wells—	wells that are producing oil or gas or that are capable of production
Proved developed reserves—	reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
Proved reserves—	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 at the end of the respective years
Proved undeveloped reserves—	reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion
Proven coal reserves—	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—	present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows using prices in effect at December 31, 2004, and estimated future costs as of December 31, 2004. Prices are held constant throughout the life of the properties except where SEC guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.
Undeveloped acreage—	lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether such acreage contains estimated net proved reserves
Working interest—	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 1A *Risk Factors*

Our business and operations are subject to a number of risks and uncertainties as described below. However, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition or results of operations. If any of the following risks actually occur, our business, financial condition or results of operations could suffer.

Risks Related to our Oil and Gas Business

Competition within our industry may adversely affect our operations.

The oil and natural gas industry is very competitive, and we compete with a substantial number of other companies that are large, well-established and have greater financial and operational resources than we do, which may adversely affect our ability to compete or grow our business. 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. 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 other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells and recruiting and retaining qualified personnel, including geologists, geo-physicists, engineers and other specialists. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. 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.

Natural gas and crude oil prices are volatile, and a substantial or extended decline in prices would hurt our profitability and financial condition.

Our revenues, operating results, cash flow, profitability, future rate of growth and the carrying value of our oil and gas properties depend heavily on prevailing market prices for natural gas and crude oil. Historically, natural gas and crude oil prices have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas and crude oil prices may result from relatively minor changes in the supply of and demand for oil and gas, market uncertainty and other factors that are beyond our control, including:

- domestic and foreign supplies of oil and natural gas;
- political and economic conditions in oil or gas producing regions;
- overall domestic and foreign economic conditions;
- prices and availability of alternative fuels;
- the availability of transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation.

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 will likely differ from our estimates. Any substantial or extended decline in the actual prices of natural gas or crude oil would have a material adverse effect on our 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.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. We have historically succeeded in substantially replacing reserves through acquisitions, exploration and development. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. Lower oil and gas prices may further limit the types of reserves that can be developed at acceptable costs. Lower prices also decrease our cash flows and may cause us to reduce capital expenditures.

The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operations are reduced and external sources of capital become limited or unavailable. In addition, exploration and development activities involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those we have consummated to date. However, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources substantially greater than those available to us. We cannot ensure that we will successfully consummate any acquisition, that we will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

We may not be able to fund our planned capital expenditures.

We make, and will continue to make, substantial capital expenditures to find, acquire, develop, exploit and produce oil and natural gas reserves. Our capital expenditures for oil and gas properties were $170 million for 2005, and we have budgeted total capital expenditures of $208 million in 2006. If oil and gas prices decrease or we encounter operating difficulties that result in our cash flow from operations being less than expected, we may have to reduce the capital we can spend unless we raise additional funds through debt or equity financing. Debt or equity financing, cash generated by operations or borrowing capacity may not be available to us in sufficient amounts or on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will be subject to a number of variables, such as:

- our success in locating and producing new reserves;
- the level of production from existing wells; and
- prices of oil and natural gas.

Issuing equity securities to satisfy our financing requirements could cause substantial dilution to existing shareholders. Debt financing could lead to us being more vulnerable to competitive pressures and economic downturns.

If our revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if we could not obtain capital through our credit facility or otherwise, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive natural gas or oil reserves will be found. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- shortages or delays in the availability of drilling rigs and the delivery of equipment;
- shortages in experienced labor;
- failure to secure necessary regulatory approvals and permits;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of oil and gas also affect the cost of and the demand for drilling rigs, production equipment and related services. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that natural gas or oil is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate for activity within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our results of operations and financial condition. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for, and the production and transportation of oil and natural gas. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures;
- pipeline ruptures or spills;
- uncontrollable flows of oil, natural gas or well fluids;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases; and
- natural disasters.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse affect on our financial condition and operations.

Our business depends on transportation facilities owned by others.

We deliver substantially all of our oil and natural gas production through pipelines that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines as well as gathering systems and processing facilities. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and market our oil and natural gas.

Competition for experienced, technical personnel may negatively impact our operations.

Our exploratory and development drilling success will depend, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. Our future profitability will depend, at least in part, on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering and operations.

Estimates of oil and natural gas reserves are not precise.

This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

At December 31, 2005, approximately 26 percent of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not assume that the present value of estimated future net cash flow referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. In addition, the 10 percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us.

We have limited control over the activities on properties we do not operate.

Other companies operate a portion of our net production. In 2005, other companies operated approximately 30 percent of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator’s expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Our producing property acquisitions carry significant risks.

Acquisition of producing oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. The success of any acquisition will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future oil and gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Responses to recent coal mining accidents could have an adverse effect on our operations.

Our conventional and CBM drilling operations in Appalachia take place in close proximity to coal mining operations. Recent coal mining disasters in West Virginia and Kentucky have received state and national attention that is resulting in increased scrutiny of current safety practices and procedures at and around coal mining operations. This scrutiny could result in the promulgation of more stringent regulations for the permitting of oil and gas wells in close proximity to coal mining operations, which could make it more difficult, time consuming and costly for us to obtain such permits and could adversely affect our natural gas production and reduce our oil and natural gas revenues.

Hedging transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of two years or less. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains if oil or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how oil or natural gas prices fluctuate in the future. We cannot assure you that our hedging transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices.

In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

We account for our derivative transactions pursuant to Statement of Financial Accounting Standards (“SFAS”) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* which requires us to record each hedging transaction as an asset or liability measured at its fair value. We must also measure the effectiveness of our hedging position in relation to the underlying commodity being hedged, and we will be required to record the ineffective portion of the hedge in our net income for that period. This accounting treatment could result in significant fluctuations in net income and shareholders’ equity from period to period.

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our financial condition and results of operations. See Item 1, "Business—Regulation—Oil and Gas—Environmental Matters."

Risks Related to our Ownership in PVR

We rely upon distributions from the Partnership, and the amount of cash that the Partnership will be able to distribute to its unitholders principally depends upon the amount of cash it can generate from its coal and natural gas midstream businesses.

We received $21.2 million of distributions from the Partnership in 2005. A significant decline in the Partnership's earnings or cash distributions would have a negative impact on us. The amount of cash that the Partnership will be able to distribute each quarter to its unitholders, including us, principally depends upon the amount of cash it can generate from its coal and midstream businesses. The amount of cash that the Partnership will generate will fluctuate from quarter to quarter based on, among other things:

- the amount of coal its lessees are able to produce;
- the price at which its lessees are able to sell the coal;
- the lessees' timely receipt of payment from their customers;
- the amount of natural gas transported in its gathering systems;
- the amount of throughput in its processing plants;
- the price of natural gas;
- the price of NGLs;
- the relationship between natural gas and NGL prices;
- the fees it charges and the margins it realizes for its midstream services; and
- its hedging activities.

In addition, the actual amount of cash that the Partnership will have available for distribution will depend on other factors, some of which are beyond its control, including:

- the level of capital expenditures it makes;
- the cost of acquisitions, if any;
- its debt service requirements;
- fluctuations in its working capital needs;
- restrictions on distributions contained in its debt agreements;
- prevailing economic conditions; and
- the amount of cash reserves established by its general partner in its sole discretion for the proper conduct of its business.

Because of these factors, the Partnership may not have sufficient available cash each quarter to pay its current declared quarterly distribution of $0.70 per unit or any other amount. You should also be aware that the amount of cash that the Partnership will have available for distribution depends primarily upon its cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Risks Related to PVR's Coal Business

If the Partnership's lessees do not manage their operations well, their production volumes and the Partnership's coal royalty revenues could decrease.

The Partnership depends on its lessees to effectively manage their operations on its properties. The Partnership's lessees make their own business decisions with respect to their operations, including decisions relating to:

- the method of mining;
- credit review of their customers;

- marketing of the coal mined;
- coal transportation arrangements;
- negotiations with unions;
- employee wages;
- permitting;
- surety bonding; and
- mine closure and reclamation.

If the Partnership's lessees do not manage their operations well, their production could be reduced, which would result in lower coal royalty revenues to the Partnership and could adversely affect its ability to make its quarterly distributions.

Coal mining operations are subject to numerous operational risks that could result in lower coal royalty revenues.

The Partnership's coal royalty revenues are largely dependent on the level of production from its coal reserves achieved by its lessees. The level of its lessees' production is subject to operating conditions or events beyond their or its control, including:

- the inability to acquire necessary permits;
- changes or variations in geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- changes in governmental regulation of the coal industry;
- mining and processing equipment failures and unexpected maintenance problems;
- adverse claims to title or existing defects of title;
- interruptions due to power outages;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions;
- employee injuries or fatalities; and
- fires and explosions.

These conditions may increase the Partnership's lessees' cost of mining and delay or halt production at particular mines for varying lengths of time. Any interruptions to the production of coal from the Partnership's reserves could reduce its coal royalty revenues and adversely affect its ability to make its quarterly distributions.

In addition, the Partnership's coal royalty revenues are based upon sales of coal by its lessees to their customers. If its lessees do not receive payments for delivered coal on a timely basis from their customers, their cash flow would be adversely affected, which could cause the Partnership's cash flow to be adversely affected and could adversely affect the Partnership's ability to make its quarterly distributions.

A substantial or extended decline in coal prices could reduce the Partnership's coal royalty revenues and the value of its coal reserves.

A substantial or extended decline in coal prices from recent levels could have a material adverse effect on the Partnership's lessees' operations and on the quantities of coal that may be economically produced from the Partnership's properties. This, in turn, could reduce the Partnership's coal royalty revenues, its coal services revenues and the value of its coal reserves. Additionally, volatility in coal prices could make it difficult to estimate with precision the value of the Partnership's coal reserves and any coal reserves that the Partnership may consider for acquisition.

The Partnership depends on a limited number of primary operators for a significant portion of its coal royalty revenues and the loss of or reduction in production from any of its major lessees could reduce its coal royalty revenues.

The Partnership depends on a limited number of primary operators for a significant portion of its coal royalty revenues. During 2005, five primary operators, each with multiple leases, accounted for 78 percent of its coal royalty revenues. If any of these operators enters bankruptcy or decide to cease operations or significantly reduce its production, the Partnership's coal royalty revenues could be reduced.

A failure on the part of the Partnership's lessees to make coal royalty payments could give the Partnership the right to terminate the lease, repossess the property or obtain liquidation damages and/or enforce payment obligations under the lease. If the Partnership repossessed any of its properties, it would seek to find a replacement lessee. It may not be able to find a replacement lessee and, if it finds a replacement lessee, it may not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If the Partnership enters into a new lease, the replacement operator might not achieve the same levels of production or sell coal at the same price as the lessee it replaced. In addition, it may be difficult for the Partnership to secure new or replacement lessees for small or isolated coal reserves, since industry trends toward consolidation favor larger-scale, higher technology mining operations to increase productivity rates.

The Partnership's coal business will be adversely affected if it is unable to replace or increase its reserves through acquisitions.

Because its reserves decline as its lessees mine its coal, the Partnership's future success and growth depends, in part, upon its ability to acquire additional coal reserves that are economically recoverable. If the Partnership is unable to negotiate purchase contracts to replace or increase its coal reserves on acceptable terms, its coal royalty revenues will decline as its coal reserves are depleted. In addition, if the Partnership is unable to successfully integrate the companies, businesses or properties it is able to acquire, its coal royalty revenues may decline and the Partnership could, therefore, experience a material adverse effect on its business, financial condition or results of operations. If the Partnership acquires additional coal reserves, there is a possibility that any acquisition could be dilutive to earnings and reduce its ability to make distributions to unitholders, including us, or to pay interest on, or the principal of, its debt obligations. Any debt the Partnership incurs to finance an acquisition may similarly affect its ability to make distributions to unitholders, including us, or to pay interest on, or the principal of, its debt obligations. The Partnership's ability to make acquisitions in the future also could be limited by restrictions under its existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

Lessees could satisfy obligations to their customers with coal from properties other than the Partnership's, depriving it of the ability to receive amounts in excess of the minimum royalty payments.

The Partnership does not control its lessees' business operations. Its lessees' customer supply contracts do not generally require its lessees to satisfy their obligations to their customers with coal mined from the Partnership's reserves. Several factors may influence a lessee's decision to supply its customers with coal mined from properties the Partnership does not own or lease, including the royalty rates under the lessee's lease with the Partnership, mining conditions, transportation costs and availability and customer coal specifications. If a lessee satisfies its obligations to its customers with coal from properties the Partnership does not own or lease, production under its lease will decrease, and it will receive lower coal royalty revenues.

Competition within the coal industry may adversely affect the ability of the Partnership's lessees to sell coal at high prices, which could reduce its coal royalty revenues.

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 United States for domestic sales. The industry has undergone significant consolidation which has led to some of the competitors of the Partnership's lessees having significantly larger financial and operating resources than most of its lessees. The Partnership's lessees 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 its lessees obtain are also affected by demand for electricity, demand for metallurgical coal, access to transportation, 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 its 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 which permit the high sulfur coal to meet federal Clean Air Act requirements. Competition among coal producers could result in excess production capacity in the industry, resulting in downward pressure on prices. Declining prices reduce the Partnership's coal royalty revenues and adversely affect its ability to make distributions to unitholders, including us, and to service its debt obligations.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal mined from the Partnership's properties.

Transportation costs represent a significant portion of the total cost of coal for the customers of the Partnership's lessees. Increases in transportation costs could make coal a less competitive source of energy or could make coal produced by some or all of the Partnership's lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for the Partnership's lessees from coal producers in other parts of the country.

The Partnership's lessees depend upon rail, barge, trucking, overland conveyor and other systems to deliver coal to their customers. Disruption of these transportation services due to weather-related problems, strikes, lockouts, bottlenecks and other events could temporarily impair the ability of the Partnership's lessees to supply coal to their customers. The Partnership's lessees' transportation providers may face difficulties in the future and impair the ability of its lessees to supply coal to their customers, thereby resulting in decreased coal royalty revenues to the Partnership.

The Partnership's lessees could experience labor disruptions, and its lessees' workforces could become increasingly unionized in the future.

Two of the Partnership's lessees each have one mine operated by unionized employees. One of these mines was the Partnership's second largest mine on the basis of coal reserves as of December 31, 2005. All of the Partnership's lessees could become increasingly unionized in the future. If some or all of the Partnership's lessees' non-unionized operations were to become unionized, it could adversely affect their productivity and increase the risk of work stoppages. In addition, the Partnership's lessees' operations may be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against its lessees' operations. Any further unionization of the Partnership's lessees' employees could adversely affect the stability of production from its reserves and reduce its coal royalty revenues.

The Partnership's reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of its reserves.

The Partnership's estimates of its reserves may vary substantially from the actual amounts of coal its lessees may be able to economically recover. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Partnership's control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data or which differ from the Partnership's experiences in areas where its lessees currently mine;
- the amount of ultimately recoverable coal in the ground;
- the effects of regulation by governmental agencies; and
- future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

Actual production, revenues and expenditures with respect to the Partnership's reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on the coal reserve data provided herein.

Any change in fuel consumption patterns by electric power generators away from the use of coal could affect the ability of the Partnership's lessees to sell the coal they produce and thereby reduce its coal royalty revenues.

According to the U.S. Department of Energy, domestic electric power generation accounts for approximately 90 percent of domestic coal consumption. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas, fuel oil and hydroelectric power and environmental and other governmental regulations. The Partnership believes that most new power plants will be built to produce electricity during peak periods of demand. Many of these new power plants will likely be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the Clean Air Act may result in more electric power generators shifting from coal to natural gas-fired power plants. See Item 1, "Business—Regulation—Coal—Air Emissions."

Extensive environmental laws and regulations affecting electric power generators could have corresponding effects on the ability of the Partnership's lessees to sell the coal they produce and thereby reduce its coal royalty revenues.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the ultimate consumers of the coal the Partnership's lessees produce. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less of these emissions, possibly further reducing demand for the coal that the Partnership's lessees produce and thereby reducing its coal royalty revenues. See Item 1, "Business—Regulation—Coal—Air Emissions."

Delays in the Partnership's lessees obtaining mining permits and approvals, or the inability to obtain required permits and approvals, could have an adverse effect on its coal royalty revenues.

Mine operators, including the Partnership's lessees, must obtain numerous permits and approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required by the Partnership's lessees to conduct operations may not be issued, maintained or renewed, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict its lessees' ability to economically conduct their mining operations. Limitations on the Partnership's lessees' ability to conduct their mining operations due to the inability to obtain or renew necessary permits could have an adverse effect on its coal royalty revenues. See Item 1, "Business—Regulation—Coal—Mining Permits and Approvals."

The Partnership's lessees' mining operations are subject to extensive and costly laws and regulations, and such current and future laws and regulations could increase operating costs and limit its lessees' ability to produce coal, which could have an adverse effect on its coal royalty revenues.

The Partnership's lessees are subject to numerous and detailed federal, state and local laws and regulations affecting coal mining operations, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. The Partnership's lessees are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be significant and time-consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations (or judicial interpretations of existing laws and regulations) may be adopted in the future that could materially affect the Partnership's lessees' mining operations, either through direct impacts such as new requirements impacting its lessees' existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit coal consumers' use of coal. Any of these direct or indirect impacts could have an adverse effect on the Partnership's coal royalty revenues. See Item 1, "Business—Regulation."

Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, the Partnership does not believe violations by its lessees can be eliminated completely. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens and, to a lesser extent, the issuance of injunctions to limit or cease operations. The Partnership's lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If the Partnership's lessees are required to pay these costs and liabilities and if their financial viability is affected by doing so, then their mining operations and, as a result, the Partnership's coal royalty revenues and its ability to make distributions, could be adversely affected.

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that are likely to result in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. These recent events could also potentially result in the promulgation of more stringent mine safety laws and regulations, or amendments to existing mine safety laws, including increased sanctions for non-compliance. These potential future mine safety laws and regulations or amendments to existing mine safety laws and regulations, and the cost of compliance with such, could adversely affect the Partnership's lessees' coal production which could have an adverse affect on its coal royalty revenues and its ability to make distributions.

Risks Related to PVR's Midstream Business

The success of the Partnership's midstream business depends upon its ability to find and contract for new sources of natural gas supply.

In order to maintain or increase throughput levels on the Partnership's gathering systems and asset utilization rates at its processing plants, the Partnership must contract for new natural gas supplies. The primary factors affecting its ability to connect new supplies of natural gas to its gathering systems include its success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity creating new gas supply near its gathering systems. The Partnership may not be able to obtain additional contracts for natural gas supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. The Partnership has no control over the level of drilling activity in its areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, the Partnership has no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital.

A substantial portion of the Partnership's midstream assets, including its gathering systems and processing plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. The Partnership's cash flows associated with these systems will decline unless it is able to access new supplies of natural gas by connecting additional production to these systems. A material decrease in natural gas production in its areas of operation, as a result of depressed commodity prices or otherwise, would result in a decline in the volume of natural gas the Partnership handles, which would reduce its revenues and operating income. In addition, the Partnership's future growth will depend, in part, upon whether it can contract for additional supplies at a greater rate than the rate of natural decline in its currently connected supplies.

The Partnership may not be able to retain existing customers or acquire new customers, which would reduce its revenues and limit its future profitability.

The renewal or replacement of existing contracts with the Partnership's customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond its control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets the Partnership serves.

The profitability of the Partnership's midstream business is dependent upon prices and market demand for natural gas and NGLs, which are beyond its control and have been volatile.

The Partnership is subject to significant risks due to fluctuations in commodity prices. During 2005, it generated a majority of its gross margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs—percentage-of-proceeds and keep-whole arrangements.

Virtually all of the natural gas gathered on the Crescent System and the Hamlin System is contracted under percentage-of-proceeds arrangements. The natural gas gathered on the Beaver System is contracted primarily under either percentage-of proceeds or gas purchase/keep-whole arrangements. Under both types of arrangements, the Partnership provides gathering and processing services for natural gas received. Under percentage-of-proceeds arrangements, the Partnership generally sells the NGLs produced from the processing operations and the remaining residue gas at market prices and remits to the producers an agreed upon percentage of the proceeds based upon an index price for the gas and the price received for the NGLs. Under these percentage-of-proceeds arrangements, revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have a material adverse effect on the Partnership's results of operations. Under gas purchase/keep-whole arrangements, the Partnership generally buys natural gas from producers based upon an index price and then sells the NGLs and the remaining residue gas to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the volume of natural gas available for sale, profitability is dependent on the value of those NGLs being higher than the value of the volume of gas reduction or "shrink." Under these arrangements, revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs. Accordingly, a change in the relationship between the price of natural gas and the price of NGLs could have a material adverse effect on the Partnership's results of operations.

In the past, the prices of natural gas and NGLs have been extremely volatile, and the Partnership expects this volatility to continue. The markets and prices for residue gas and NGLs depend upon factors beyond the Partnership's control. These factors include demand for oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions, and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

The Partnership encounters competition from other midstream companies.

The Partnership experiences competition in all of its midstream markets. Competition is based on many factors, including geographic proximity to production, costs of connection, available capacity, rates and access to markets. The Partnership's competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of the Partnership's competitors have greater financial resources and access to larger natural gas supplies than it does.

Expanding the Partnership's midstream business by constructing new gathering systems, pipelines and processing facilities subjects it to construction risks.

One of the ways the Partnership may grow its midstream business is through the construction of additions to existing gathering, compression and processing systems. The construction of a new gathering system or pipeline or the expansion of an existing pipeline, by adding additional horsepower or pump stations or by adding a second pipeline within an existing right of way, and the construction of new processing facilities, involve numerous regulatory, environmental, political and legal uncertainties beyond the Partnership's control and require the expenditure of significant amounts of capital. If the Partnership undertakes these projects, they may not be completed on schedule, or at all, or at the budgeted cost. Moreover, the Partnership's revenues may not increase immediately upon the expenditure of funds on a particular project. For example, the construction of gathering facilities requires the expenditure of significant amounts of capital, which may exceed the Partnership's estimates. Generally, the Partnership may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, the Partnership may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. As a result, there is the risk that new facilities may not be able to attract enough natural gas to achieve the Partnership's expected investment return, which could adversely affect its financial position or results of operations.

If the Partnership is unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then it may be unable to fully execute its growth strategy and its cash flows could be reduced.

The construction of additions to the Partnership's existing gathering assets may require it to obtain new rights-of-way before constructing new pipelines. The Partnership may be unable to obtain rights-of-way to connect new natural gas supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for the Partnership to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then the Partnership's cash flows could be reduced.

The Partnership is exposed to the credit risk of its midstream customers, and nonpayment or nonperformance by its customers could reduce its cash flows.

The Partnership is subject to risk of loss resulting from nonpayment or nonperformance by its customers. The Partnership depends on a limited number of customers for a significant portion of its midstream revenue. For 2005, two customers represented 46 percent of total natural gas midstream revenues and 23 percent of our total consolidated revenues. Any nonpayment or nonperformance by our customers could reduce our cash flows.

Any reduction in the capacity of, or the allocations to, the Partnership in interconnecting third-party pipelines could cause a reduction of volumes processed, which would adversely affect its revenues and cash flow.

The Partnership is dependent upon connections to third-party pipelines to receive and deliver residue gas and NGLs. Any reduction of capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures or other causes could result in reduced volumes gathered and processed in its midstream facilities. Similarly, if additional shippers begin transporting volumes of residue gas and NGLs on interconnecting pipelines, the Partnership's allocations in these pipelines would be reduced. Any reduction in volumes gathered and processed in the Partnership's facilities would adversely affect its revenues and cash flow.

Hedging transactions may limit the Partnership's potential gains and involve other risks.

In order to manage its exposure to price risks in the marketing of its natural gas and NGLs, the Partnership periodically enters into natural gas and NGL price hedging arrangements with respect to a portion of its expected production. Its hedges are limited in duration, usually for periods of two years or less. However, in connection with acquisitions, sometimes its hedges are for longer periods. While intended to reduce the effects of volatile natural gas and NGL prices, such transactions may limit the Partnership's potential gains if natural gas or NGL prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, the Partnership may end up hedging too much or too little, depending upon how natural gas or NGL prices fluctuate in the future. We cannot assure you that the Partnership's hedging transactions will reduce the risk or minimize the effect of any decline in natural gas or NGL prices.

In addition, hedging transactions may expose the Partnership to the risk of financial loss in certain circumstances, including instances in which:

- its production is less than expected;
- there is a widening of price basis differentials between delivery points for its production and the delivery point assumed in the hedge arrangement;
- the counterparties to its futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts natural gas or NGL prices.

The Partnership accounts for its derivative transactions pursuant to SFAS No. 133, which requires it to record each hedging transaction as an asset or liability measured at its fair value. The Partnership must also measure the effectiveness of its hedging position in relation to the underlying commodity being hedged, and the Partnership will be required to record the ineffective portion of the hedge in its net income for that period. This accounting treatment could result in significant fluctuations in our net income and shareholders' equity from period to period.

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

The Partnership's midstream business involves many hazards and operational risks, some of which may not be fully covered by insurance.

The Partnership's midstream operations are subject to the many hazards inherent in the gathering, compression, treating, processing and transportation of natural gas and NGLs, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons; and
- fires and explosions.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of the Partnership's related operations. The Partnership's midstream operations are concentrated in Texas and Oklahoma, and a natural disaster or other hazard affecting these areas could have a material adverse effect on its operations. The Partnership is not fully insured against all risks incident to its midstream business. The Partnership does not have property insurance on all of its underground pipeline systems that would cover damage to the pipelines. The Partnership is not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect the Partnership's operations and financial condition.

Federal, state or local regulatory measures could adversely affect the Partnership's midstream business.

Cantera Gas Company ("CGC"), a wholly owned subsidiary of PVR Midstream LLC, owns and operates an 11-mile interstate natural gas pipeline which, pursuant to the NGA, is subject to the jurisdiction of the FERC. The FERC has granted CGC waivers of various requirements otherwise applicable to conventional FERC-jurisdictional pipelines, including the obligation to file a tariff governing rates, terms and conditions of open access transportation service. The FERC has determined that CGC will have to comply with the filing requirements if the natural gas company ever desires to apply for blanket transportation authority to transport third-party gas on the 11-mile pipeline. We cannot assure you that the FERC will maintain these waivers.

The Partnership's natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but FERC regulation nevertheless could significantly affect its gathering business and the market for its services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which the Partnership's gathering pipelines deliver. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

In Texas, the Partnership's gathering facilities are subject to regulation by the Texas Railroad Commission, which has the authority to ensure that rates, terms and conditions of gas utilities, including certain gathering facilities, are just and reasonable and not discriminatory. The Partnership's operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits it from charging any unduly discriminatory fees for its gathering services. We cannot predict whether the Partnership's gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

The Partnership is subject to ratable take and common purchaser statutes in Texas and Oklahoma. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting the Partnership's right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and Texas and Oklahoma have adopted complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. We cannot assure you that federal and state authorities will retain their current regulatory policies in the future.

Texas and Oklahoma administer federal pipeline safety standards under the NGPSA, which requires certain pipelines to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. In response to recent pipeline accidents, Congress and the U.S. Department of Transportation have recently instituted heightened pipeline safety requirements. Certain of the Partnership's gathering facilities are exempt from these federal pipeline safety requirements under the rural gathering exemption. We cannot assure you that the rural gathering exemption will be retained in its current form in the future.

Failure to comply with applicable regulations under the NGA, the NGPSA and certain state laws can result in the imposition of administrative, civil and criminal remedies.

The Partnership's midstream business is subject to extensive environmental regulation.

Many of the operations and activities of the Partnership's gathering systems, plants and other facilities are subject to significant federal, state and local environmental laws and regulations. These include, for example, laws and regulations that impose obligations related to air emissions and discharge of wastes from the Partnership's facilities and the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by Cantera or locations to which it has sent wastes for disposal. These laws and regulations can restrict or impact the Partnership's business activities in many ways, including restricting the manner in which it disposes of substances, requiring pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in the Partnership's midstream business due to its handling of natural gas and other petroleum products, air emissions related to its midstream operations, historical industry operations, waste disposal practices and Cantera's prior use of natural gas flow meters containing mercury. For example, an accidental release from one of the Partnership's pipelines or processing facilities could subject it to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase the Partnership's compliance costs and the cost of any remediation that may become necessary. The Partnership may incur material environmental costs and liabilities. Insurance may not provide sufficient coverage in the event an environmental claim is made.

Item 1B *Unresolved Staff Comments*

We received no written comments from the SEC staff regarding our periodic or current reports under the Exchange Act within 180 days before the end of our fiscal year ended December 31, 2005.

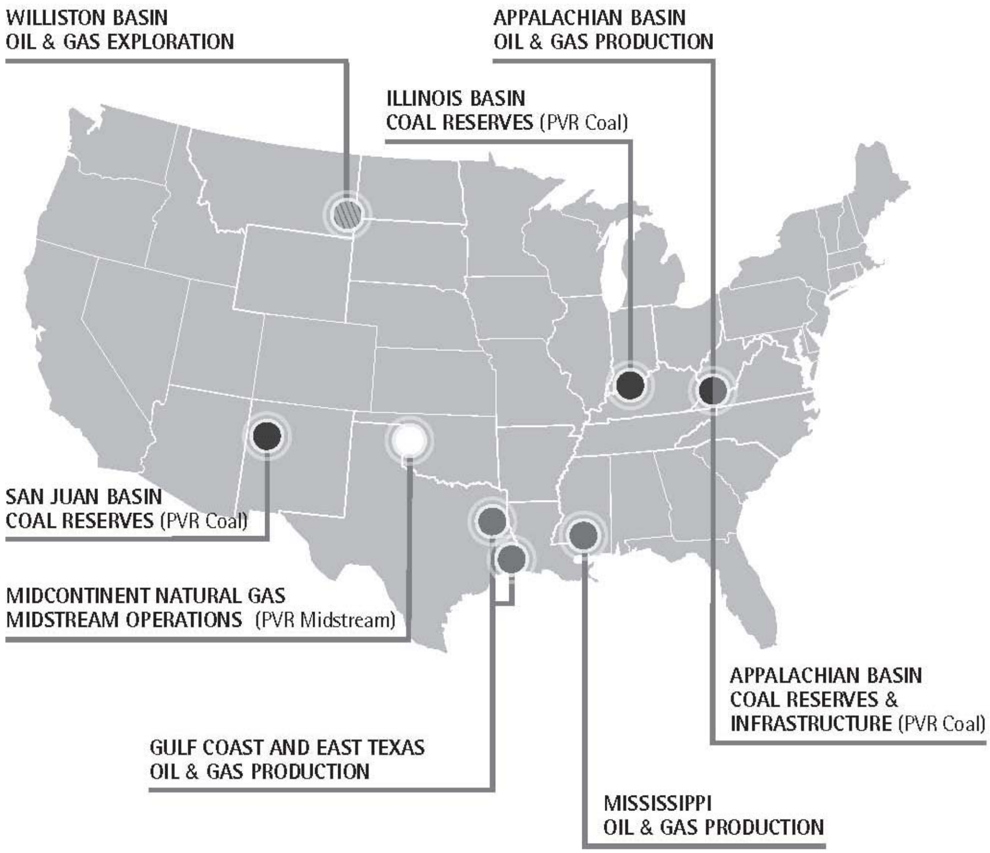
Item 2 *Properties*

Facilities

We are headquartered in Radnor, Pennsylvania, with additional offices in Tennessee, Texas and West Virginia. All of our office facilities are leased, except for PVR's West Virginia office, which it owns. We believe that our properties are adequate for our current needs.

Title to Properties

The following map shows the general locations of our oil and gas production and exploration, PVR's coal reserves, PVR's coal services and infrastructure investments and PVR's natural gas gathering and processing systems:



We believe that we have satisfactory title to all of our properties and the associated oil, gas and coal reserves in accordance with standards generally accepted in the oil and natural gas, coal and natural gas midstream 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 materially affect the value of such properties.

Of the 689 million tons of proven and probable coal reserves to which the Partnership had rights as of December 31, 2005, PVR owned the mineral interests and the majority of related surface rights to 609 million tons, or 88 percent, and leased the remaining 80 million tons, or 12 percent, from unaffiliated third parties.

PVR's natural gas midstream assets are primarily located in the mid-continent area of Oklahoma and the panhandle of Texas. The Partnership owns and operates a significant set of midstream assets that include approximately 3,450 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 MMcfd of total capacity. PVR owns, leases or has rights-of-way to the properties where the majority of its midstream facilities are located. PVR believes it has sufficient rights-of-way to accommodate its gathering systems and pipelines.

Information Regarding Oil and Gas Properties

Production and Pricing

The following table sets forth production, average sales prices and production costs with respect to our oil and gas properties for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Production:			
Oil and condensate (MBbls)	302	396	625
Natural gas (MMcf)	25,550	22,079	20,094
Total production (MMcfe)	27,362	24,455	23,844
Average sales prices:			
Natural gas ($/Mcf)			
Actual price received for production	$ 8.86	$ 6.44	$ 5.59
Effect of derivative hedging activities	(0.55)	(0.17)	(0.28)
Average realized price	$ 8.31	$ 6.27	$ 5.31
Crude oil ($/Bbl)			
Actual price received for production	$ 48.51	$ 39.09	$ 27.77
Effect of derivative hedging activities	(2.84)	(5.34)	(0.86)
Average realized price	$ 45.67	$ 33.75	$ 26.91
Production expenses ($/Mcfe):			
Lease operating	$ 0.63	$ 0.57	$ 0.51
Taxes other than income	0.48	0.38	0.40
General and administrative	0.34	0.34	0.33
Total production expenses	$ 1.45	$ 1.29	$ 1.24

Proved Reserves

The following table presents certain information regarding our proved reserves as of December 31, 2005, 2004 and 2003. The proved reserve estimates presented below were prepared by Wright and Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves, the preparation of such estimates by Wright and Company, Inc. and other information about our oil and gas reserves, see Note 24 in the Notes to Consolidated Financial Statements. Our estimates of proved reserves in the table below are consistent with those filed by us with other federal agencies.

	Oil and Condensate	Natural Gas	Natural Gas Equivalents	Standardized Measure (1)	Year-end Prices Used	
	(MMbbls)	(Bcf)	(Bcfe)	($ millions)	$ / Bbl	$ /MMbtu
2005						
Developed	2.0	267	279	$ 833		
Undeveloped	0.9	92	98	203		
Total	2.9	359	377	$ 1,036	$ 61.04	$ 10.08
2004						
Developed	2.9	243	261	$ 469		
Undeveloped	3.4	73	93	121		
Total	6.3	316	354	$ 590	$ 43.46	$ 6.18
2003						
Developed	3.3	231	251	$ 419		
Undeveloped	3.3	52	72	93		
Total	6.6	283	323	$ 512	$ 32.52	$ 5.97

(1) Standardized measure consists of future net cash flows, discounted at 10 percent. For information on the changes in the standardized measure of discounted future net cash flows, see Note 24 in the Notes to Consolidated Financial Statements.

In accordance with the SEC's guidelines, the engineers' estimates of future net revenues from our properties and the standardized measure thereof are based on oil and natural gas sales prices in effect as of December 31, 2005, and estimated future costs as of December 31, 2005. 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. Prices for oil and gas are subject to substantial seasonal fluctuations as well as fluctuations resulting from 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 standardized measure 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, 2005. The acreage is located primarily in the Appalachian, Mississippi, east Texas and Gulf Coast onshore areas of the United States.

	Gross Acreage	Net Acreage
	(in thousands)	
Developed	637	511
Undeveloped	719	482
Total	1,356	993

Wells Drilled

The following table sets forth the gross and net numbers of exploratory and development wells drilled during the last three years. The number of wells drilled refers to the number of wells reaching total depth 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.

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	163	130.8	134	89.7	161	117.0
Non-productive	3	3.0	1	0.3	1	1.0
Total development	166	133.8	135	90.0	162	118.0
Exploratory						
Productive	6	2.9	7	1.5	5	1.2
Non-productive	3	3.0	7	4.4	3	2.9
Under evaluation	3	2.5	3	2.6	10	10.0
Total exploratory	12	8.4	17	8.5	18	14.1
Total	178	142.2	152	98.5	180	132.1

The three exploratory wells under evaluation at the end of 2005 included two New Albany Shale wells in Ilinois and a Bakken Dolomite horizontal oil well in Montana. We expect to determine the commercial viability of these wells during 2006. At December 31, 2005, we had capitalized costs of $1.7 million related to these wells.

The three exploratory wells under evaluation at the end of 2004 included a horizontal Devonian shale well in West Virginia, a CBM well in Mississippi and an HCBM well in Virginia. In 2005, we determined that these wells were not commercially viable, resulting in a $3.3 million write-off.

The 10 exploratory wells under evaluation at the end of 2003 were CBM wells drilled and completed in the Cherokee Basin in Chase and Greenwood Counties, Kansas. In 2004, we determined that these wells were not commercially viable, resulting in a $4.4 million write-off.

Productive Wells

The number of productive oil and gas wells in which we had a working interest at December 31, 2005, 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
938	892.0	563	93.6	1,501	985.6

In addition to the above working interest wells, we own royalty interests in 1,882 gross wells.

Information Regarding Coal Properties

At December 31, 2005, the Partnership’s coal reserves were located on approximately 336,000 acres, including fee and leased acreage, in Kentucky, New Mexico, Virginia and West Virginia. The coal reserves are in various surface and underground seams. As of December 31, 2005, the Partnership had approximately 689 million tons of proven and probable coal reserves, which are found in the following properties:

- the central Appalachia property, located in Buchanan, Lee and Wise Counties, Virginia; Floyd, Harlan, Knott and Letcher Counties, Kentucky; and Boone, Fayette, Kanawha, Lincoln, Logan and Raleigh Counties, West Virginia;
- the northern Appalachia property, located in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;
- the Illinois Basin property, located in Henderson and Webster Counties, Kentucky; and
- the San Juan Basin property, located in McKinley County, New Mexico.

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, workings or drill holes; (b) grade and/or quality are computed from the results of detailed sampling; and (c) 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. 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 more widely spaced 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 exploration to ensure the continuity and mineablility of coal reserves. Consequently, sampling in those areas involves drill holes or channel samples 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 and low in sulfur.

The amount of coal that 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 following table sets forth production data and reserve information with respect to each of the Partnership's properties:

	Production Year Ended December 31,			**Proven and Probable Reserves at December 31, 2005**		
Property	**2005**	**2004**	**2003**	**Under-ground**	**Surface**	**Total**
			(tons in millions)			
Central Appalachia	19.0	20.1	15.1	373.2	120.5	493.7
Northern Appalachia	5.0	5.6	5.1	37.4	2.2	39.6
Illinois Basin	1.4	—	—	78.5	14.3	92.8
San Juan Basin	4.8	5.5	6.3	—	63.0	63.0
Total	30.2	31.2	26.5	489.1	200.0	689.1

The following table sets forth the coal reserves the Partnership owns and leases with respect to each of its coal properties as of December 31, 2005:

Property	**Owned**	**Leased**	**Total**
		(tons in millions)	
Central Appalachia	417.8	75.9	493.7
Northern Appalachia	39.6	—	39.6
Illinois Basin	92.8	—	92.8
San Juan Basin	59.1	3.9	63.0
Total	609.3	79.8	689.1

The Partnership's coal reserve estimates were prepared from geological data assembled and analyzed by PVR's general partner's geologists and engineers. These estimates are compiled using geological data taken from thousands of drill holes, geophysical logs, adjacent mine workings, outcrop prospect openings and other sources. These estimates also take into account legal, qualitative, technical and economic limitations that may keep coal from being mined. Reserve estimates will change from time to time due to mining activities, analysis of new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods and other factors

Information Regarding Natural Gas Midstream Properties

The following table sets forth information regarding PVR's natural gas midstream assets as of December 31, 2005:

					Ten Months Ended December 31, 2005 (3)	
Asset	**Type**	**Approximate Length (Miles)**	**Approximate Wells Connected**	**Processing Capacity (Mmcfd) (1)**	**Average Plant Throughput (Mmcfd)**	**Utilization of Processing Capacity (%)**
Beaver/Perryton System	Gathering pipelines and processing facility	1,180	868	100	87.0	87.0%
Crescent System	Gathering pipelines and processing facility	1,675	937	40	18.5	46.3%
Hamlin System	Gathering pipelines and processing facility	517	243	20	6.6	33.0%
Arkoma System	Gathering pipelines	78	86	—	14.9(2)	—
					127.0	

(1) Many capacity values are based on current operating configurations and could be increased through additional compression, increased delivery meter capacity or other facility upgrades.
(2) Gathering only volumes.
(3) Includes the results of operations since March 3, 2005, the closing date of the Cantera Acquisition.

PVR's midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services.

Item 3 *Legal Proceedings*

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. See Item 1, "Business—Regulation," for a more detailed discussion of our material environmental obligations.

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 2005.

PART II

Item 5 *Market for the Registrant's Common Equity and Related Shareholder Matters and Issuer Purchases of Equity Securities*

Market Information

Our common stock is traded on the New York Stock Exchange under the symbol "PVA." The high and low sales prices (composite transactions) and dividends paid for each fiscal quarter in 2005 and 2004 were as follows:

Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2005	$ 62.76	$ 51.15	$ 0.1125
September 30, 2005	$ 58.40	$ 44.59	$ 0.1125
June 30, 2005	$ 49.32	$ 38.05	$ 0.1125
March 31, 2005	$ 50.52	$ 37.55	$ 0.1125
December 31, 2004	$ 45.34	$ 35.23	$ 0.1125
September 30, 2004	$ 40.85	$ 33.02	$ 0.1125
June 30, 2004	$ 37.07	$ 30.19	$ 0.1125
March 31, 2004 (1)	$ 30.58	$ 26.39	$ 0.1125

(1) For comparative purposes, sales prices and dividends declared have been adjusted for the effect of a two-for-one stock split on June 10, 2004. See Note 7 in the Notes to Consolidated Financial Statements.

Equity Holders

As of March 8, 2006, there were approximately 595 record holders and approximately 6,500 beneficial owners (held in street name) of our common stock.

Item 6 *Selected Financial Data*

	Year Ended December 31,				
	2005 (1)	2004	2003	2002	2001
	(in thousands except share data)				
Revenues	$ 673,864	$ 228,425	$ 181,284	$ 110,957	$ 96,571
Operating income (2)	$ 162,017	$ 80,796	$ 62,101	$ 30,791	$ 1,563
Net income (3)	$ 62,088	$ 33,355	$ 28,522	$ 12,104	$ 34,337
Per common share: (4)					
Net income, basic	$ 3.35	$ 1.82	$ 1.59	$ 0.68	$ 1.96
Net income, diluted	$ 3.31	$ 1.81	$ 1.58	$ 0.67	$ 1.93
Dividends paid	$ 0.45	$ 0.45	$ 0.45	$ 0.45	$ 0.45
Cash flows provided by operating activities (5)	$ 231,407	$ 146,365	$ 109,704	$ 65,788	$ 44,191
Total assets (6)	$ 1,251,546	$ 783,335	$ 683,733	$ 586,292	$ 457,102
Long-term debt, net of current portion	$ 325,846	$ 188,926	$ 154,286	$ 106,887	$ 46,887
Minority interest in PVR	$ 313,524	$ 182,891	$ 190,508	$ 192,770	$ 144,039
Shareholders' equity	$ 310,560	$ 252,860	$ 211,648	$ 187,956	$ 185,454

(1) The 2005 column includes the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) Operating income in 2004 included a $7.5 million loss on assets held for sale. Operating income in 2005, 2004, 2003, 2002 and 2001 included a $4.8 million, $0.7 million, $0.4 million, $0.8 million and $33.6 million impairment of 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) For comparative purposes, amounts per common share in 2001 through 2003 have been adjusted for the effect of a two-for-one stock split on June 10, 2004. See Note 7 in the Notes to Consolidated Financial Statements.
(5) Certain reclassifications have been made to conform to the current year presentation.
(6) Total assets in 2005 reflect the Cantera Acquisition.

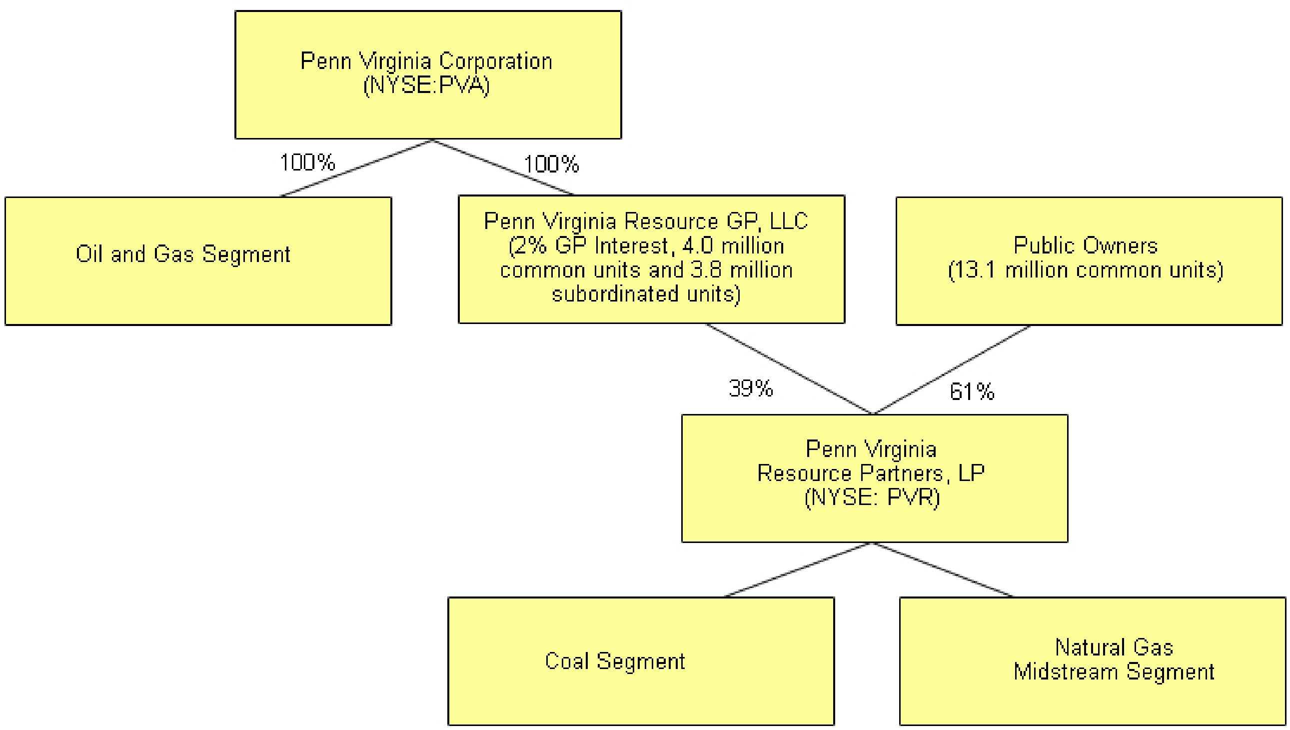
Item 7 ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following analysis of financial condition and results of operations of Penn Virginia Corporation and its subsidiaries should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data." Our discussion and analysis include the following items:

- Overview of Business
- Overview of 2005 Performance
- Acquisitions and Investments
- Critical Accounting Policies and Estimates
- Liquidity and Capital Resources
- Contractual Obligations
- Off-Balance Sheet Arrangements
- Results of Operations
- Environmental
- Recent Accounting Pronouncements
- Forward-Looking Statements

Overview of Business

We are an independent energy company that is engaged in three primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal and natural gas midstream segments operate through our 39 percent ownership in PVR. Penn Virginia and PVR are publicly traded on the New York Stock Exchange under the symbols "PVA" and "PVR." Due to our control of the general partner of PVR, the financial results of the Partnership are included in our consolidated financial statements. However, PVR functions with a capital structure that is independent of ours, consisting of its own debt instruments and publicly traded common units. The following diagram depicts our ownership of PVR as of December 31, 2005:



As a result of our ownership in the Partnership, we receive cash payments from PVR in the form of quarterly cash distributions. We received approximately $21.2 million of cash distributions from PVR during 2005. 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 distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. See Item 1, "Business—Partnership Distributions—Incentive Distribution Rights." The cash payments we received from PVR in 2005 and 2004 were as follows (in thousands):

	Year Ended December 31,	
	2005	2004
Limited partner units	$ 19,281	$ 16,511
General partner interest (2%)	1,021	788
Incentive distribution rights	910	—
Total	$ 21,212	$ 17,299

In November 2004, 25 percent of PVR's subordinated units converted to common units because the Partnership met certain requirements to qualify for early conversion. In November 2005, another 25 percent converted to common units. The remaining 50 percent of PVR's subordinated units are expected to convert to common units in November 2006, provided minimum quarterly distributions are paid and other conditions are met. See Item 1, "Business—Partnership Distributions," for more information on incentive distribution rights and subordinated units.

Overview of 2005 Performance

Operating income for 2005 was $162.0 million. The oil and gas segment, combined with the operating results of corporate, contributed $83.9 million to operating income, and PVR's coal and natural gas midstream segments, of which we own a 39 percent interest, contributed $78.1 million, before the deduction of the 61 percent interest that we do not own. A description of each of our reportable segments follows:

- Oil and Gas – crude oil and natural gas exploration, development and production.
- Coal – the leasing of mineral interests and subsequent collection of royalties, the providing of fee-based coal handling, transportation and processing infrastructure facilities and the development and harvesting of timber.
- Natural Gas Midstream – gas processing, gathering and other related services.
- Corporate and Other – primarily represents corporate functions.

Oil and Gas Segment

Our oil and gas strategy has been to increase our presence in CBM and unconventional natural gas to build a significant inventory of predictable, low risk development prospects and to selectively drill higher risk exploration opportunities which could make a meaningful difference to our production and reserve profile. During 2005, we made progress in each area as our oil and gas production increased by 12 percent to 27.4 Bcfe. Commodity prices also contributed significantly to our financial results in 2005. Price volatility in the natural gas market has been high in the last few years, with the NYMEX futures market trading at record price levels for natural gas. Our realized natural gas price in 2005 was $8.31 per Mcf, an increase of 33 percent from $6.27 per Mcf in 2004. As part of our risk management strategy, we use financial instruments to hedge natural gas and, to a lesser extent, oil prices. The use of this risk management strategy has resulted in lower price realizations compared to physical sale prices in the last several years.

Our total oil and gas reserves at the end of 2005 were 376 Bcfe, an increase of six percent over the end of 2004. Approximately 95 percent of our reserves at year-end 2005 were natural gas. Net of revisions, we added approximately 77 Bcfe of proved reserves, primarily from extensions, discoveries and additions. We drilled a total of 178 gross (142.2 net) wells during 2005, including 166 gross (133.8 net) development wells and 12 gross (8.4 net) exploratory wells. Three development wells (3.0 net) and three gross (3.0 net) exploratory wells were not successful and three gross (2.5 net) exploratory wells were under evaluation at December 31, 2005.

Early in 2004, we entered into a joint venture with GMX Resources, Inc. (NASDAQ: GMXR) to drill development wells in the North Carthage Field in east Texas. Through the end of 2005, 37 gross (26.4 net) wells were drilled on this acreage, and we estimate that a total of 80 to 100 wells could ultimately be drilled.

During 2005, we continued to expand our CBM production and reserve base in central Appalachia through leasehold acquisitions and the use of a proprietary horizontal drilling technology.

Coal Segment

Coal prices, especially in central Appalachia where the majority of PVR's production is located, have increased significantly since the beginning of 2003. The price increase stems from several causes including increased electricity demand and decreasing coal production in central Appalachia. PVR's coal royalty revenues increased 19 percent from $69.6 million in 2004 to $82.7 million in 2005. This increase was a result of a 23 percent increase in average gross royalties per ton from $2.23 in 2004 to $2.74 in 2005.

PVR also earns coal services revenues related to its ownership of coal preparation plants, coal loading facilities and its 50 percent interest in a coal handling joint venture with Massey. Coal services revenues increased to $5.2 million in 2005 from $3.8 million in 2004. PVR believes that these types of fee-based infrastructure assets provide good investment and cash flow opportunities for the Partnership, and it continues to look for additional investments of this type as well as other primarily fee-based assets.

Natural Gas Midstream Segment

As a result of the Cantera Acquisition in March 2005, PVR owns and operates a set of midstream assets primarily located in the mid-continent area of Oklahoma and the panhandle of Texas that include approximately 3,450 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 MMcfd of total capacity. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. The Cantera Acquisition also included a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. We believe that the Cantera Acquisition established a platform for future growth in the natural gas midstream sector and diversified PVR's cash flows into another long-lived asset base.

For the ten months ended December 31, 2005, PVR's midstream operations generated a gross processing margin of $44.7 million, consisting of midstream revenues minus the cost of gas purchased. Inlet volumes at PVR's gas processing plants and gathering systems were 38.9 Bcf, or approximately 127 MMcfd, for the same ten-month period, with a gross processing margin of $1.15 per Mcf.

Acquisitions and Investments

Oil and Gas Segment

Panther Acquisition. In June 2005, we acquired approximately 60,000 acres of prospective CBM leasehold rights in Wyoming County, West Virginia, from Panther Energy Company, LLC, for $13.3 million in cash (the "Panther Acquisition"). The leasehold acreage is within an area of mutual interest between Penn Virginia and CDX and is contiguous to acreage which has been successfully developed. The purchase agreement included an option for CDX to purchase a 50 percent interest in the leasehold acreage. In August 2005, CDX exercised that option and acquired its 50 percent interest for $6.6 million in cash. We began drilling on the new leasehold position in the fourth quarter of 2005.

Coal Segment

Coal River Acquisition. In March 2005, PVR acquired lease rights to approximately 36 million tons of undeveloped coal reserves and royalty interests in 73 producing oil and natural gas wells for $9.3 million in cash (the "Coal River Acquisition"). The coal reserves are located in the central Appalachia region of West Virginia. The oil and gas wells are located in eastern Kentucky and southwestern Virginia. The Coal River Acquisition was funded with long-term debt under PVR's revolving credit facility. The coal reserves are predominantly low sulfur and high BTU content, and development will occur in conjunction with PVR's adjacent reserves and a related loadout facility that was placed into service in 2004. The oil and gas property contains approximately 2.8 Bcfe of net proved oil and gas reserves with current net production of approximately 0.2 Bcfe on an annualized basis.

Alloy Acquisition. In April 2005, PVR acquired fee ownership of approximately 16 million tons of coal reserves for $15.0 million in cash (the "Alloy Acquisition"). The reserves, located on approximately 8,300 acres in the central Appalachia region of West Virginia, will be produced from deep and surface mines. Production started in late 2005. Revenues were earned initially from wheelage fees on coal mined from an adjacent property, followed by royalty revenues as the mines on PVR's property commenced production. The seller remained on the property as the lessee and operator. The Alloy Acquisition was funded with long-term debt under PVR's revolving credit facility.

Wayland Acquisition. In July 2005, PVR acquired a combination of fee ownership and lease rights to approximately 16 million tons of coal reserves for $14.5 million (the "Wayland Acquisition"). The reserves are located in the eastern Kentucky portion of central Appalachia. The Wayland Acquisition was funded with $4 million of cash and the issuance by PVR to the seller of approximately 209,000 common units. In addition, PVR assumed $0.7 million of liabilities related to the acquired property. During the third quarter of 2005, PVR began constructing a new preparation plant and unit train coal loading facility on the property, which it expects to complete during 2006 at an estimated total capital expenditure of $12.5 million. The reserves have been leased to an operator who will commence the mining of raw coal on a very limited basis during construction of the loading facility. After completion of the facility, PVR expects the operator's production from the property to increase to approximately one million tons of coal per year in 2007. PVR also expects to earn fees from third party operators for coal processed from adjacent properties.

Green River Acquisition. In July 2005, PVR acquired fee ownership of approximately 94 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for $62.4 million in cash (the "Green River Acquisition"), and PVR assumed $3.3 million of deferred income. This coal reserve acquisition is PVR's first in the Illinois Basin and was funded with long-term debt under PVR's revolving credit facility. Currently, approximately 45 million tons of these coal reserves are leased to affiliates of Peabody Energy Corporation (NYSE: BTU) ("Peabody"). PVR expects the remaining coal reserves to be leased over the next several years, with a gradual increase in coal production and related cash flow from the property.

Coal Handling Joint Venture . In July 2004, the Partnership acquired from affiliates of Massey a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was $28.4 million and was funded with long-term debt under the Partnership's revolving credit facility. The joint venture owns coal handling facilities which unload shipments and store and transfer coal for three industrial coal consumers in the chemical, paper and lime production industries located in Tennessee, Virginia and Kentucky. A combination of fixed monthly fees and per ton throughput fees is paid by those consumers under long-term leases expiring between 2007 and 2019. PVR recognized equity earnings of $1.1 million in 2005 and $0.4 million in 2004 related to its ownership in the joint venture. The Partnership received joint venture distributions of approximately $2.3 million in 2005 and $1.0 million in 2004.

Natural Gas Midstream Segment

Cantera Acquisition. On March 3, 2005, PVR completed its acquisition of Cantera, a midstream gas gathering and processing company with primary locations in the mid-continent area of Oklahoma and the panhandle of Texas. Cash paid in connection with the Cantera Acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which PVR funded with a $110 million term loan and with long-term debt under its revolving credit facility. PVR used the proceeds from its sale of common units in a subsequent public offering in March 2005 to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. See Note 4 in the Notes to Consolidated Financial Statements for pro forma financial information.

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting policies which involve the judgment of our management.

Reserves

The estimates of oil and gas reserves are the single most critical estimate included in our financial statements. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of 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 wells with existing equipment and operating methods. Proved undeveloped reserves are those quantities that require additional capital investment through drilling or well recompletion techniques.

Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments, and the fair value of properties subject to potential impairments.

There are several factors which could change our estimates of oil and gas reserves. Significant rises or declines in product prices could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. Additionally, we perform impairment tests pursuant to SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates.

Depreciation and depletion of oil and gas producing properties is determined by the units-of-production method and could change with revisions to estimated proved recoverable reserves.

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. The Partnership's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively.

Oil and Gas Revenues

Revenues associated with sales of natural gas, crude oil, condensate and natural gas liquids are recorded when title passes to the customer. Natural gas sales revenues from properties in which we have an interest with other producers are recognized on the basis of our net working interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. Any amount received in excess of our share is treated as deferred revenues. If we take less than we are entitled to take, the under-delivery is recorded as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, accruals for revenues and accounts receivable are made based on estimates of our share of production, particularly from properties that are operated by our partners. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized. Approximately 54 percent of natural gas and oil and condensate revenues in 2005 related to two customers.

Natural Gas Midstream Revenues

Revenue from the sale of NGLs and residue gas is recognized when the NGLs and residue gas produced at PVR's gas processing plants are sold. Gathering and transportation revenue is recognized based upon actual volumes delivered. Due to the time needed to gather information from various purchasers and measurement locations and then calculate volumes delivered, the collection of natural gas midstream revenues may take up to 30 days following the month of production. Therefore, accruals for revenues and accounts receivable and the related cost of gas purchased and accounts payable are made based on estimates of natural gas purchased and NGLs and natural gas sold, and our financial results include estimates of production and revenues for the period of actual production. Any differences, which we do not expect to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized. Approximately 46 percent of natural gas midstream revenues in 2005 related to two customers.

Coal Royalty Revenues

Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenues from those sales. Since PVR does not operate any mines, it does not have access to actual production and revenue information until approximately 30 days following the month of production. Therefore, the financial results of the Partnership include estimated revenues and accounts receivable for this 30-day period. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Hedging Activities

We and PVR enter into derivative financial instruments that qualify for hedge accounting under SFAS No. 133. Hedge accounting affects the timing of revenue recognition in our statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until realized. The position reflected in the statement of income is based on the actual settlements with the counterparty. We include this gain or loss in oil and gas revenues, natural gas midstream revenues or cost of gas purchased, depending on the hedged commodity. If our derivatives did not qualify for hedge accounting or we chose not to use hedge accounting, we could experience significant changes in the estimate of non-cash derivative gain or loss recognized in revenue due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2005, the costs attributable to unproved properties were approximately $66.7 million. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. Unproved properties whose acquisition costs are not relatively significant are amortized in the aggregate over the lesser of five years or the average remaining lease term. As exploration work progresses and the reserves on relatively significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations

In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations,* we make estimates of the timing and future costs of plugging and abandoning wells. Estimated abandonment dates will be revised in the future based on changes to related economic lives, which vary with product prices and production costs. Estimated plugging costs may also be adjusted to reflect changing industry experience. Our cash flows would not be affected until plugging and abandoning wells actually occurs.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, the Company and PVR operate with independent capital structures. The Company and PVR have separate credit facilities, and neither entity guarantees the debt of the other. Since PVR's inception in 2001, with the exception of cash distributions paid to us by PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and issuance of new Partnership units. We expect that our cash needs and the cash needs of PVR will continue to be met independently of each other with a combination of these funding sources. Summarized cash flow statements for 2005 and 2004 consolidating our combined segments are set forth below.

For the year ended December 31, 2005 (in thousands)	Oil and Gas and Corporate	PVR Coal and PVR Midstream	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 49,536	$ 12,552	$ 62,088
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	101,770	78,045	179,815
Net change in operating assets and liabilities	(13,611)	3,115	(10,496)
Net cash provided by operating activities	137,695	93,712	231,407
Cash flows from investing activities:			
Additions to property and equipment	(171,651)	(12,735)	(184,386)
Acquisitions	—	(290,938)	(290,938)
Other	17,333	52	17,385
Net cash used in investing activities	(154,318)	(303,621)	(457,939)
Cash flows from financing activities:			
PVA dividends paid	(8,358)	—	(8,358)
PVR distributions received (paid)	21,212	(51,949)	(30,737)
Proceeds received from (paid for) issuance of partners' capital	(2,783)	129,239	126,456
PVA debt proceeds, net of repayments	3,000	—	3,000
PVR debt proceeds, net of repayments	—	137,200	137,200
Other	1,798	(2,385)	(587)
Net cash provided by (used in) financing activities	14,869	212,105	226,974
Net increase, (decrease) in cash and cash equivalents	(1,754)	2,196	442
Cash and cash equivalents—beginning of year	4,474	20,997	25,471
Cash and cash equivalents—end of year	$ 2,720	$ 23,193	$ 25,913

For the year ended December 31, 2004 (in thousands)	Oil and Gas and Corporate	PVR Coal	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 24,115	$ 9,240	$ 33,355
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	82,974	39,661	122,635
Net change in operating assets and liabilities	(15,506)	5,881	(9,625)
Net cash provided by operating activities	91,583	54,782	146,365
Cash flows from investing activities:			
Additions to property and equipment	(124,153)	(1,088)	(125,241)
Acquisitions	—	(28,442)	(28,442)
Other	1,222	1,104	2,326
Net cash used in investing activities	(122,931)	(28,426)	(151,357)
Cash flows from financing activities:			
PVA dividends paid	(8,248)	—	(8,248)
PVR distributions received/(paid)	17,299	(39,191)	(21,892)
PVA debt proceeds, net of repayments	12,000	—	12,000
PVR debt proceeds, net of repayments	—	26,000	26,000
Other	5,829	(1,234)	4,595
Net cash provided by (used in) financing activities	26,880	(14,425)	12,455
Net increase, (decrease) in cash and cash equivalents	(4,468)	11,931	7,463
Cash and cash equivalents—beginning of year	8,942	9,066	18,008
Cash and cash equivalents—end of year	$ 4,474	$ 20,997	$ 25,471

Cash Flows

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

From 2004 to 2005, the oil and gas and corporate segments' net cash provided by operations increased primarily due to increased natural gas production and increased prices received for natural gas and crude oil. We used cash from operating activities during both years to help fund capital expenditures. Cash provided by operations of the coal and natural gas midstream segments increased primarily due to the natural gas midstream business acquired in March 2005 and an increase in average royalties per ton resulting from higher coal sales prices. PVR's acquisition of its natural gas midstream segment was accretive to operating cash flows during 2005.

During 2004 and 2003, we used cash primarily for capital expenditures for oil and gas development and exploration activities and acquisitions of oil and gas properties. During 2004, PVR acquired an interest in the Massey coal handling joint venture for $28.4 million.

Capital expenditures totaled $489.2 million in 2005, compared with $165.9 million in 2004 and $144.0 million in 2003. The following table sets forth capital expenditures by segment made during the periods indicated:

	Year ended December 31,		
	2005	2004	2003
		(in thousands)	
Oil and gas			
Development drilling	$ 107,744	$ 77,033	$ 59,551
Exploration drilling	18,562	16,411	11,931
Seismic	7,836	10,018	9,470
Lease acquisition and other (1)	30,297	13,046	44,152
Pipeline, gathering, facilities	5,138	18,669	7,770
Total	169,577	135,177	132,874
Coal			
Coal reserve and lease acquisitions (2) (3)	106,489	1,293	6,330
Acquisition of coal handling joint venture interest	—	28,442	—
Support equipment and facilities (4)	6,008	855	4,128
Total	112,497	30,590	10,458
Natural gas midstream			
Acquisitions, net of cash acquired	199,223	—	—
Other property and equipment expenditures	7,588	—	—
Total	206,811	—	—
Other	350	176	621
Total capital expenditures	$ 489,235	$ 165,943	$ 143,953

(1) Amount in 2003 includes $33.5 million to acquire proved oil and gas properties in south Texas.
(2) Amount in 2005 includes noncash expenditure of $11.1 million to acquire coal reserves in Kentucky in the Wayland Acquisition in exchange for $10.4 million of equity issued in the form of Partnership common units and $0.7 million of liabilities assumed. Amount in 2005 also includes the noncash portion of the Green River Acquisition, in which PVR assumed $3.3 million of deferred income. Amounts in 2004 and 2003 include noncash expenditures of $1.1 million and $5.2 million to acquire additional reserves on PVR's northern Appalachia properties in exchange for equity issued in the form of Partnership common and Class B units.
(3) Amount in 2005 includes $0.4 million of noncash expenditures due to the timing of payment of invoices.
(4) Amount in 2005 includes $0.8 million of noncash expenditures due to the timing of payment of invoices.

We are committed to expanding our oil and gas operations over the next several years through a combination of exploration, development and acquisition of new properties. We have a portfolio of assets which balances relatively low risk, moderate return development projects in Appalachia, Mississippi and the Cotton Valley in east Texas and north Louisiana with relatively moderate risk, potentially higher return development projects and exploration prospects in south Texas and south Louisiana.

We have budgeted approximately $208 million for oil and gas segment capital expenditures in 2006. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area 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 2006 planned oil and gas capital expenditures program.

During 2005, PVR made aggregate capital expenditures of $291.3 million for the Cantera Acquisition and four coal reserve acquisitions. To finance its 2005 acquisitions, PVR borrowed $137.2 million, net of repayments, received proceeds of $126.4 million from the sale of its common units in a public offering and received a $2.6 million contribution from its general partner, which is a wholly owned subsidiary of the Company. To finance its equity investment in the Massey coal handling joint venture in 2004, PVR borrowed $26.0 million, net of repayments. In 2003, PVR received $90.0 million in proceeds from a private placement of senior unsecured notes, which it used to repay a $43.4 million term loan and to repay most of the outstanding debt on its revolving credit facility at the time.

We borrowed under our revolving credit facility, net of repayments, $3.0 million in 2005, $12.0 million in 2004 and $47.9 million in 2003. We also received cash distributions from PVR of $21.2 million in 2005, $17.3 million in 2004 and $16.8 million in 2003. Funds from both of these sources were primarily used for capital expenditures.

Long-Term Debt

Revolving Credit Facility. In December 2003, we entered into a revolving credit facility (the "Revolver") with a syndicate of financial institutions led by JP Morgan Chase Bank N.A. The Revolver is secured by a portion of our proved oil and gas reserves. In December 2005, we amended and restated the Revolver to increase the commitment from $150 million to $200 million, increase the borrowing base from $200 million to $300 million, extend the maturity date from December 2007 to December 2010 and attain a more favorable interest rate. We paid loan issue costs of $0.5 million related to the amendment, which were capitalized in other assets and will be amortized over the remaining term of the Revolver. We had $79 million outstanding under the Revolver as of December 31, 2005, giving us approximately $121 million of available borrowing capacity. The Revolver is governed by a borrowing base calculation and is redetermined semi-annually. We have the option to elect interest at (i) the London Interbank Offering Rate ("LIBOR") plus a Eurodollar margin ranging from 1.00 to 1.75 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 up to 0.50 percent. The weighted average interest rate on borrowings incurred during the year ended December 31, 2005, was approximately 4.99 percent. In 2005, we incurred commitment fees of $0.3 million on the unused portion of the Revolver. We capitalized $3.5 million of interest cost incurred in 2005. The Revolver allows for the issuance of up to $20 million of letters of credit, of which $0.3 million were issued as of December 31, 2005.

The financial covenants under the Revolver require us to maintain levels of debt-to-earnings and impose dividend limitation restrictions. The Revolver contains various other covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2005, we were in compliance with all of our covenants under the Revolver.

Line of Credit. We have a $5.0 million line of credit with a financial institution, which had no borrowings against it as of December 31, 2005. The line of credit is effective through June 2006 and is renewable annually. We have an option to elect either a fixed rate LIBOR loan, a floating rate LIBOR loan or a base rate (as determined by the financial institution) loan.

PVR Revolving Credit Facility. Concurrent with the closing of the Cantera Acquisition in March 2005, PVR entered into a new unsecured $260 million, five-year credit agreement with a syndicate of financial institutions led by PNC Bank, National Association. The new agreement consisted of a $150 million revolving credit facility (the "PVR Revolver") that matures in March 2010 and a $110 million term loan. As of December 31, 2005, PVR had $172.0 million outstanding under the PVR Revolver. A portion of the PVR Revolver and the term loan were used to fund the Cantera Acquisition and to repay borrowings under PVR's previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million of PVR's common units in March 2005 and a $2.6 million contribution from its general partner were used to repay the $110 million term loan and a portion of the amount outstanding under the PVR Revolver. In the fourth quarter of 2004, PVR paid loan issue costs of approximately $1.2 million related to the term loan, which were recorded as interest expense in 2004. The term loan cannot be re-borrowed. The PVR Revolver is available for general Partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR had outstanding letters of credit of $1.6 million as of December 31, 2005. In 2005, PVR incurred commitment fees of $0.4 million on the unused portion of the PVR Revolver.

In July 2005, PVR amended its credit agreement to increase the size of the commitment under the PVR Revolver from $150 million to $300 million and to increase its one-time option (upon receipt by the credit facility's administrative agent of commitments from one or more lenders) to expand the PVR Revolver from $100 million to $150 million. The amendment also updated certain debt covenant definitions. The interest rate under the credit agreement remained unchanged and will fluctuate based on PVR's ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if PVR selects the base rate borrowing option under the credit agreement or at a rate derived from LIBOR plus an applicable margin ranging from 1.00 percent to 2.00 percent if PVR selects the LIBOR-based borrowing option. The other terms of the credit agreement remained unchanged.

The financial covenants under the PVR Revolver require PVR to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR's borrowing capacity under the PVR Revolver to approximately $106.5 million as of December 31, 2005. The PVR Revolver prohibits PVR from making distributions to its unitholders (including us) and distributions in excess of available cash if any potential default or event of default, as defined in the PVR Revolver, occurs or would result from the distribution. In addition, the PVR Revolver contains various covenants that limit, among other things, PVR's ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of its business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2005, PVR was in compliance with all of its covenants in the PVR Revolver.

PVR Senior Unsecured Notes. As of December 31, 2005, PVR owed $83.0 million under its senior unsecured notes (the "PVR Notes"). The PVR Notes initially bore interest at a fixed rate of 5.77 percent and mature over a ten-year period ending in March 2013, with semi-annual principal and interest payments. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. The PVR Notes have an equal priority of payment as all other unsecured indebtedness of PVR, including the PVR Revolver. As of December 31, 2005, PVR was in compliance with all of its covenants under the PVR Notes.

In conjunction with the closing of the Cantera Acquisition, PVR amended the PVR Notes to allow PVR to enter the natural gas midstream business and to increase certain covenant coverage ratios, including the debt to EBITDA test. In exchange for this amendment, PVR agreed to a 0.25 percent increase in the fixed interest rate on the PVR Notes, from 5.77 percent to 6.02 percent. The amendment to the PVR Notes also requires that the Partnership obtain an annual confirmation of its credit rating, with a 1.00 percent increase in the interest rate payable on the PVR Notes in the event its credit rating falls below investment grade. On March 15, 2005, PVR's investment grade credit rating was confirmed by Dominion Bond Rating Services.

Interest Rate Swaps. In September 2005, PVR entered into two interest rate swap agreements with notional amounts totaling $60 million to establish a fixed rate on the LIBOR-based portion of the outstanding balance of the PVR Revolver until March 2010 (the "PVR Revolver Swaps"). PVR pays a fixed rate of 4.22 percent on the notional amount, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the PVR Revolver Swaps are recorded as interest expense. The PVR Revolver Swap agreements were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 1.25 percent in effect as of December 31, 2005, the total interest rate on the $60 million portion of the PVR Revolver borrowings covered by the PVR Revolver Swaps was 5.47 percent at December 31, 2005.

In March 2003, PVR entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of the PVR Notes (the "PVR Senior Notes Swap"). The PVR Senior Notes Swap agreement was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by PVR to the counterparty in July 2005. The $0.8 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the PVR Notes using the effective interest rate method.

Future Capital Needs and Commitments

We are committed to increasing value to our shareholders by conducting a balanced program of investment in all three of our business segments. In the oil and gas segment, we expect to continue to execute a program combining relatively low risk, moderate return development drilling in Appalachia, Mississippi, east Texas and north Louisiana with higher risk, higher return exploration and development drilling in the onshore Gulf Coast, supplemented periodically with acquisitions. In addition to our continuing conventional development program, we have continued to expand our presence in unconventional plays by developing CBM gas reserves in Appalachia. By employing horizontal drilling techniques, we expect to continue to increase the value from the CBM-prospective properties we own. We are committed to expanding our oil and gas reserves and production primarily by using our ability to generate exploratory prospects and development drilling programs internally.

Part of PVR's strategy is to make acquisitions which increase cash available for distribution to its unitholders. Long-term cash requirements for asset acquisitions are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities and the issuance of additional equity and debt securities. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time.

In 2006, we anticipate making total capital expenditures, excluding acquisitions, of approximately $241 million. All of these expenditures are expected to be funded primarily by operating cash flow. Additional funding will be provided as needed from our Revolver, under which we had $121 million of borrowing capacity as of December 31, 2005, or from the PVR Revolver, under which PVR had $128 million of borrowing capacity as of December 31, 2005.

Budgeted capital expenditures for 2006 are $208 million in the oil and gas segment and $3.4 million for corporate building and software improvements. The Partnership anticipates making capital expenditures, excluding acquisitions, in 2006 of $16 to $18 million for coal services projects and other property and equipment and $8 to $10 million for natural gas midstream system expansion projects. The Partnership believes that cash flow provided by operating activities will be sufficient to fund these capital expenditures.

Contractual Obligations

Our contractual cash obligations as of December 31, 2005, were as follows:

	Payments Due by Period				
	Total	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**Thereafter**
			(in thousands)		
Revolving credit facility	$ 79,000	$ —	$ 79,000	$ —	$ —
PVR revolving credit facility	172,000	—	—	172,000	—
PVR senior unsecured notes	83,700	8,300	23,700	27,500	24,200
Rental commitments (1)	9,566	4,412	3,953	1,201	—
Firm transportation agreements	10,854	1,769	2,690	2,162	4,233
Total contractual cash obligations	$ 355,120	$ 14,481	$ 109,343	$ 202,863	$ 28,433

(1) Rental commitments primarily relate to equipment and building leases. Also included are PVR'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 PVR will incur approximately $0.6 million in rental commitments in perpetuity until the reserves have been exhausted.

Off-Balance Sheet Arrangements

At December 31, 2005, we did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Results of Operations

Selected Financial Data—Consolidated

	2005	2004	2003
	(in millions, except per share data)		
Revenues	$ 673.9	$ 228.4	$ 181.3
Expenses	$ 511.8	$ 147.6	$ 119.2
Operating income	$ 162.0	$ 80.8	$ 62.1
Net income (1)	$ 62.1	$ 33.4	$ 28.5
Earnings per share, basic	$ 3.35	$ 1.82	$ 1.59
Earnings per share, diluted	$ 3.31	$ 1.81	$ 1.58
Cash flows provided by operating activities	$ 231.4	$ 146.4	$ 109.7

(1) Net income for 2003 included $1.4 million, or $0.08 per diluted share, related to the adoption of *SFAS* No. 143. The oil and gas segment's contribution to net income includes this amount.

The increase in 2005 net income compared to 2004 net income was primarily attributable to increased operating income from our oil and gas segment and our coal segment as well as the contribution of a natural gas midstream business that was acquired in the first quarter of 2005. These increases in net income were partially offset by increased interest expense on PVR's additional borrowings to fund acquisitions. A net unrealized loss on derivatives offset the increase in net income.

The assets, liabilities and earnings of PVR are fully consolidated in our financial statements, with the public unitholders' interest (61 percent as of December 31, 2005) reflected as a minority interest.

Oil and Gas Segment

In our oil and gas segment, we explore for, develop, produce and sell crude oil, condensate and natural gas primarily in the Appalachian, Mississippi, east Texas and Gulf Coast onshore regions of the United States. 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 our 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.

Operations and Financial Summary—Oil and Gas Segment

Year Ended December 31, 2005, Compared to Year Ended December 31, 2004

	2005	2004	% Change	2005	2004
	(in thousands, except as noted)			(per MMcfe)*	
Production					
Natural gas (MMcf)	25,550	22,079	16%		
Oil and condensate (MBbls)	302	396	(24)%		
Total production (MMcfe)	27,362	24,455	12%		
Revenues					
Natural gas					
Revenue received for production	$ 226,476	$ 142,192	59%	$ 8.86	$ 6.44
Effect of hedging activities	(14,049)	(3,770)	273%	(0.55)	(0.17)
Net revenue realized	212,427	138,422	53%	8.31	6.27
Oil and condensate					
Revenue received for production	14,649	15,480	(5)%	48.51	39.09
Effect of hedging activities	(857)	(2,116)	(59)%	(2.84)	(5.34)
Net revenue realized	13,792	13,364	3%	45.67	33.75
Other income	600	(114)	(626)%		
Total revenues	226,819	151,672	50%	8.29	6.20
Expenses					
Operating	17,300	13,949	24%	0.63	0.57
Taxes other than income	13,188	9,325	41%	0.48	0.38
General and administrative	9,264	8,336	11%	0.34	0.34
Production costs	39,752	31,610	26%	1.45	1.29
Exploration	40,917	26,058	57%	1.50	1.07
Depreciation, depletion and amortization	45,885	35,886	28%	1.68	1.47
Loss on assets held for sale	—	7,541	—	—	0.31
Impairment of properties	4,785	655	631%	0.17	0.03
Total expenses	131,339	101,750	29%	4.80	4.17
Operating income	$ 95,480	$ 49,922	91%	$ 3.49	$ 2.03

* Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per Bbl, and all other amounts are shown per Mcfe.

Production. The increase in production was primarily due to new production from increased drilling, including the HCBM play in Appalachia, the Selma Chalk development play in Mississippi and the Cotton Valley play in east Texas and north Louisiana. Production increases were partially offset by the first quarter 2005 sale of oil and gas properties in west Texas, production shut-ins along the Gulf Coast as a result of hurricanes Katrina and Rita and normal field declines.

Revenues. Approximately 93 percent and 90 percent of production in 2005 and 2004 was natural gas. Increased natural gas production accounted for approximately $21.8 million, or 29 percent, of the increase in natural gas revenues. Increased realized prices for natural gas accounted for approximately $52.2 million, or 71 percent, of the increase in natural gas revenues. The average realized price received for natural gas during 2005 was $8.31 per Mcf compared with $6.27 per Mcf in 2004, a 33 percent increase. The average realized oil price received was $45.67 per barrel in 2005, up 35 percent from $33.75 per barrel in 2004. This price increase for crude oil was offset by a decline in oil production compared to 2004 due to the January 2005 sale of oil and gas properties in West Texas, production shut-ins along the Gulf Coast as a result of hurricanes Katrina and Rita and normal field declines.

Due to the volatility of crude oil and natural gas prices, we hedge the price received for certain sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In 2005, approximately 42 percent of our natural gas was hedged using costless collars at an average floor price of $5.61 per MMbtu and an average ceiling price of $8.10 per MMbtu. We also hedged approximately 31 percent of our crude oil production using a fixed price swap in January 2005 and a costless collar beginning in March 2005 and continuing for the remainder of the year. The swap price was $30.59 per barrel, and the costless collar had a floor price of $42.00 per barrel and a ceiling price of $47.75 per barrel. We recognized a loss on settled derivative contracts accounted for as cash flow hedges of $14.9 million in 2005, compared with a loss of $5.9 million in 2004.

Expenses. The oil and gas segment's aggregate operating costs and expenses in 2005 increased primarily due to increases in operating expenses, exploration expenses, taxes other than income, general and administrative expenses, impairments and depreciation, depletion and amortization ("DD&A") expenses. These increases were partially offset by the absence in 2005 of a loss on assets held for sale.

Operating expenses increased primarily due to additional compressor rentals at fields with increased production, downhole maintenance charges associated with HCBM wells in Appalachia and Selma Chalk wells in Mississippi and increased water disposal costs.

Exploration expenses for the years ended December 31, 2005 and 2004, consisted of the following (in thousands):

	2005	2004
Dry hole costs	$ 11,379	$ 10,284
Seismic	7,739	9,225
Unproved leasehold write-offs	17,761	5,726
Other	4,038	823
Total	$ 40,917	$ 26,058

Exploration expenses increased primarily due to higher unproved leasehold write-offs and dry hole costs for an unsuccessful exploratory well in south Texas. The balance of the increase in exploration expenses was primarily due to unproved leasehold write-offs relating to expired lease options and increased delay rentals on certain leaseholds in south Louisiana.

Taxes other than income increased due to higher severance taxes as a result of increased production and higher gas prices. General and administrative expenses increased primarily due to increased payroll costs as a result of wage increases and new personnel. Impairment charges in 2005 related to changes in estimates of reserve bases of certain fields in Texas.

Oil and gas DD&A expenses increased due to the 12 percent increase in equivalent production and as a result of higher average depletion rates. The average depletion rate increased from $1.47 per Mcfe in 2004 to $1.67 per Mcfe in 2005 as a result of a greater percentage of production coming from relatively higher cost. HCBM and Cotton Valley wells and general price inflation for equipment, services and tubulars used for drilling and development, combined with depreciation on new pipeline infrastructure placed in service during the fourth quarter of 2004.

A loss of $7.5 million was recognized in 2004 for the write-down to realizable value of a group of non-core properties in west Texas that were sold in January 2005.

Year Ended December 31, 2004, Compared to Year Ended December 31, 2003

	2004	2003	% Change	2004	2003
	(in thousands, except as noted)			(per MMcfe)*	
Production					
Natural gas (MMcf)	22,079	20,094	10%		
Oil and condensate (MBbls)	396	625	(37)%		
Total production (MMcfe)	24,455	23,844	3%		
Revenues					
Natural gas					
Revenue received for production	$ 142,192	$ 112,193	27%	$ 6.44	$ 5.59
Effect of hedging activities	(3,770)	(5,578)	(32)%	(0.17)	(0.28)
Net revenue realized	138,422	106,615	30%	6.27	5.31
Oil and condensate					
Revenue received for production	15,480	17,355	(11)%	39.09	27.77
Effect of hedging activities	(2,116)	(539)	293%	(5.34)	(0.86)
Net revenue realized	13,364	16,816	(21)%	33.75	26.91
Other income	(114)	1,391			
Total revenues	151,672	124,822	22%	6.20	5.23
Expenses					
Lease operating	13,949	12,115	15%	0.57	0.51
Taxes other than income	9,325	9,515	(2)%	0.38	0.40
General and administrative	8,336	7,804	7%	0.34	0.33
Production costs	31,610	29,434	7%	1.29	1.24
Exploration	26,058	15,503	68%	1.07	0.65
Depreciation, depletion and amortization	35,886	33,164	8%	1.47	1.39
Loss on assets held for sale	7,541	—	—	0.31	—
Impairment of properties	655	406	61%	0.03	0.02
Total expenses	101,750	78,507	30%	4.17	3.30
Income before income taxes	$ 49,922	$ 46,315	8%	$ 2.03	$ 1.93

* Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per Bbl, and all other amounts are shown per Mcfe.

Production. The increase in production was primarily due to production from successful exploratory drilling projects in south Louisiana, the Cotton Valley play in east Texas and north Louisiana, increased drilling in our Selma Chalk fields in Mississippi and our HCBM drilling project in Appalachia, offset primarily by production declines in several south Texas fields and a pipeline curtailment in Appalachia.

Revenues. Increased realized prices for natural gas and crude oil accounted for approximately $24.0 million, or 89 percent, of the increase in total oil and gas revenues from 2003 to 2004. Approximately 90 percent of our 2004 production was natural gas, for which the average realized price received was $6.27 per Mcf compared with $5.31 per Mcf in 2003, an 18 percent increase. The average realized oil price received was $33.75 per barrel for 2004, up 25 percent from $26.91 per barrel in 2003.

Due to the volatility of crude oil and natural gas prices, we hedge the price received for certain sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In 2004, approximately 36 percent of our natural gas was hedged, primarily using costless collars, at an average floor price of $3.93 per MMbtu and ceiling price of $5.99 per MMbtu. We also hedged approximately 45 percent of our crude oil production using fixed price swaps with an average price of $29.78 per barrel. We recognized a loss on settled hedging activities of $5.9 million in 2004, compared with a loss of $6.1 million in 2003.

Operating expenses. The oil and gas segment's aggregate operating costs and expenses in 2004 increased primarily due to higher exploration expenses, higher DD&A and a loss on assets held for sale.

Exploration expenses for the years ended December 31, 2004 and 2003, consisted of the following (in thousands):

	2004	2003
Dry hole costs	$ 10,284	$ 5,186
Seismic	9,225	8,713
Unproved leasehold write-offs	5,726	802
Other	823	802
Total	$ 26,058	$ 15,503

Exploration expenses increased primarily due to increased unproved leasehold write-offs related to expiring lease options in south Texas, unproved leasehold write-offs and dry hole costs related to our CBM pilot drilling program in Kansas and higher dry hole costs resulting from drilling seven unsuccessful exploratory wells in 2004 compared to three unsuccessful exploratory attempts in 2003.

As a percentage of revenues, taxes other than income decreased from 7.6 percent in 2003 to 6.1 percent in 2004. The decrease was primarily due to a severance tax refund received in the fourth quarter of 2004 related to the south Texas properties acquired in 2003.

Oil and gas DD&A increased primarily due to higher production as discussed previously, and the weighted average DD&A rate increased from $1.39 per Mcfe in 2003 to $1.49 per Mcfe in 2004. The increase in the weighted average DD&A rate was the result of a greater percentage of production coming from relatively higher cost HCBM and Gulf Coast wells and the new pipeline infrastructure placed in service during the fourth quarter of 2004.

A loss of $7.5 million loss on assets held for sale resulted from the write-down to realizable value of a group of non-core properties in west Texas which were sold in January 2005.

Coal Segment

The coal segment includes coal reserves, coal services, timber and other land assets. 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. The Partnership does not operate any mines. Approximately 83 percent of coal royalty revenues in 2005 and 79 percent of coal royalty revenues in 2004 were derived from coal mined on PVR's properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of coal royalty revenues for the respective periods was derived from coal mined on PVR's properties under leases containing fixed royalty rates which escalate annually. In addition to coal royalty revenues, the Partnership generates coal services revenues from fees charged to lessees for the use of its coal preparation and loading facilities and from equity earnings from the Massey joint venture. The Partnership also generates revenues from the sale of standing timber on its properties, the collection of wheelage fees and oil and natural gas well royalties.

Coal royalties are impacted by several factors that 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 lessees' customers to change operations significantly or incur substantial costs.

Operations and Financial Summary—PVR Coal

Year Ended December 31, 2005, Compared to Year Ended December 31, 2004

	2005	2004	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$ 82,725	$ 69,643	19%
Coal services	5,230	3,787	38%
Other	7,800	2,200	255%
Total revenues	95,755	75,630	27%
Expenses			
Operating	5,755	7,224	(20)%
Taxes other than income	1,129	948	19%
General and administrative	9,237	8,307	8%
Operating expenses before non-cash charges	16,121	16,479	(4)%
Depreciation, depletion and amortization	17,890	18,632	(4)%
Total expenses	34,011	35,111	(4)%
Operating income	$ 61,744	$ 40,519	53%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	30,227	31,181	(3)%
Average royalty per ton ($/ton)	$ 2.74	$ 2.23	23%

Revenues. Coal royalty revenues increased due to a higher average royalty per ton despite a three percent decrease in production. The average royalty per ton increased to $2.74 in 2005 from $2.23 in 2004. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced under certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by PVR's lessees decreased primarily due to a loss of production resulting from one lessee's longwall mining operation moving off of PVR's property and onto an adjacent third party property in the first quarter of 2005. Production also decreased due to the inability of one lessee's customer to receive shipments because of an operating problem at the customer's power generation facility. These decreases were partially offset by production from property acquired in the Green River Acquisition in the Illinois Basin.

The increase in coal services revenues primarily related to increased equity earnings from the coal handling joint venture in which PVR acquired a 50 percent in July 2004. Increased revenues from two coal handling facilities that began operating in July 2003 and February 2004 also contributed to the increase.

Other revenues increased primarily due to the following factors. PVR received approximately $1.3 million of additional wheelage fees primarily as a result of the Alloy Acquisition in April 2005. PVR also received $1.5 million during the second quarter of 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents. PVR received approximately $1.4 million of royalty income in 2005 from the oil and natural gas royalty interests acquired in the March 2005 Coal River Acquisition, approximately $0.8 million for fees for the management of certain coal properties and approximately $0.4 million of rental income from railcars purchased in the second quarter of 2005.

Expenses. Operating expenses decreased due to a decrease in production from subleased properties, partially offset by new wheelage expenses incurred as a result of the April 2005 Alloy Acquisition. Production from subleased properties decreased by 32 percent to 4.6 million tons in 2005 from 6.8 million tons in 2004. General and administrative expenses increased primarily due to increased accounting and tax related fees and increased payroll costs due to new personnel and wage increases. The decrease in DD&A expense is consistent with the decrease in production.

Year Ended December 31, 2004, Compared to Year Ended December 31, 2003

	2004	2003	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$ 69,643	$ 50,312	38%
Coal services	3,391	2,111	61%
Other	2,596	3,219	(19)%
Total revenues	75,630	55,642	36%
Expenses			
Operating	7,224	4,235	71%
Taxes other than income	948	1,256	(25)%
General and administrative	8,307	7,013	18%
Operating expenses before non-cash charges	16,479	12,504	32%
Depreciation, depletion and amortization	18,632	16,578	12%
Total expenses	35,111	29,082	21%
Operating income	40,519	26,560	53%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	31,181	26,463	18%
Average royalty per ton ($/ton)	$ 2.23	$ 1.90	17%

Revenues. Coal royalty revenues increased due to increased production by PVR's lessees and higher royalty rates. The increase in the average gross royalty per ton accounted for 54 percent of the increase in coal royalty revenues and was primarily due to stronger market conditions for coal and the resulting higher coal prices. The increase in production accounted for the remaining 46 percent of the overall increase in coal royalty revenues. Production increased when, in the first quarter of 2004, one lessee's longwall mining operation moved onto one of PVR's subleased central Appalachia properties from an adjacent third party property. The addition of a new mine operator and new mines in PVR's central Appalachia properties also contributed to increased production.

Coal services revenues increased primarily as a result of start-up operations at two coal handling facilities that began operating in July 2003 and February 2004. Equity earnings from a coal handling joint venture in which PVR acquired a 50 percent interest in July 2004 also contributed to the increase.

Other revenues decreased primarily due decreases in minimum rentals and timber revenues. Minimum rental revenues decreased primarily due to the timing of expiring recoupments from PVR's lessees. The amount recognized in 2003 primarily related to four leases. Each of these leases was assigned to a new lessee approved by PVR. The leases were amended at the time of assignment to allow the new lessees additional time to offset actual production against minimum rental payments. Timber revenues decreased due to the timing of a parcel sale of standing timber in 2003 and poor weather conditions in the second quarter of 2004. These decreases were partially offset by a gain on the 2004 sale of surface property in Virginia.

Expenses. Operating expenses increased due to an increase in production by lessees on PVR's subleased properties. Production from subleased properties doubled to 7.8 million tons in 2004 from 3.9 million tons in 2003. The decrease in taxes other than income was attributable to the assumption by a new lessee of the property tax obligation on PVR's Coal River property for which PVR had been responsible since the bankruptcy of PVR's initial Coal River lessee. General and administrative expenses increased due to costs related to a secondary public offering for the sale of common units held by an affiliate of Peabody and increased professional fees and payroll costs relating to evaluating acquisition opportunities and compliance with the Sarbanes-Oxley Act of 2002. DD&A expense increased primarily as a result of increased production and depreciation on PVR's coal services facilities which began operations in July 2003 and February 2004.

Natural Gas Midstream Segment

PVR purchased its natural gas midstream business on March 3, 2005. The results of operations of the PVR midstream segment since that date are included in the operations and financial summary table below.

The PVR midstream segment derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. Revenues, profitability and the future rate of growth of the PVR midstream segment are highly dependent on market demand and prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have generally correlated with changes in the price of crude oil. NGL and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market uncertainty.

Operations and Financial Summary – PVR Midstream Segment

	Year Ended December 31, 2005 (1)	
	Amount (in thousands)	(per Mcf)
Financial Highlights		
Revenues		
Residue gas	$ 233,208	
Natural gas liquids	106,453	
Condensate	7,322	
Gathering and transportation fees	1,674	
Total natural gas midstream revenues	348,657	$ 8.97
Marketing revenue, net	1,936	0.05
Total revenues	350,593	9.02
Expenses		
Cost of gas purchased	303,912	7.82
Operating	9,347	0.24
Taxes other than income	1,268	0.03
General and administrative	6,981	0.18
Depreciation and amortization	12,738	0.33
Total expenses	334,246	8.60
Operating income	$ 16,347	$ 0.42
Operating Statistics		
Inlet volumes (MMcf)	38,875	
Midstream processing margin (2)	$ 44,745	$ 1.15

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) Midstream processing margin consists of total natural gas midstream revenues minus the cost of gas purchased.

Revenues. Revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from natural gas volumes connected to PVR's gas processing plants and the purchase and resale of natural gas not connected to PVR's gathering systems and processing plants. The average realized sales price was $8.97 per Mcf in 2005. Natural gas inlet volumes at PVR's three gas processing plants were approximately 38.9 Bcf in 2005.

Expenses. Operating costs and expenses primarily consisted of the cost of gas purchased and also included operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization.

Cost of gas purchased in 2005 consisted of amounts payable to third-party producers for gas purchased under percentage of proceeds and keep-whole contracts. The average purchase price for gas was $7.82 per Mcf in 2005. The midstream processing margin, consisting of total natural gas midstream revenues minus the cost of gas purchased, was $44.7 million, or $1.15 per Mcf of inlet gas.

Operating expenses are costs directly associated with the operations of the natural gas midstream segment and include direct labor and supervision, property insurance, repair and maintenance expenses, measurement and utilities. These costs are generally fixed across broad volume ranges. The fuel expense to operate pipelines and plants is more variable in nature and is sensitive to changes in volume and commodity prices; however, a large portion of the fuel cost is generally borne by PVR's producers.

General and administrative expenses consisted of costs to manage the midstream assets as well as integration costs.

Depreciation and amortization expenses for 2005 included $4.1 million in amortization of intangibles recognized in connection with the Cantera Acquisition and $8.6 million of depreciation on property, plant and equipment.

Corporate and Other

Corporate and other results primarily consist of oversight and administrative functions.

Operations and Financial Summary—Corporate and Other

	2005	2004	2003
	(in thousands, except as noted)		
Revenues			
Other	$ 697	$ 1,123	$ 820
Total revenues	697	1,123	820
Expenses			
Operating	283	600	600
Taxes other than income	420	207	551
General and administrative	11,123	9,527	10,076
Operating expenses before noncash charges	11,826	10,334	11,227
Depreciation, depletion and amortization	424	434	367
Total expenses	12,250	10,768	11,594
Operating loss	$ (11,553)	$ (9,645)	$ (10,774)

Year Ended December 31, 2005, Compared to Year Ended December 31, 2004

Other revenues and operating expenses decreased due to the elimination of intercompany rail rental revenues and expenses. In June 2005, a PVR subsidiary purchased railcars that one of our subsidiaries had previously leased from a third party. After the purchase, our subsidiary began leasing the railcars from the PVR subsidiary. Intercompany revenues and operating expense of $0.4 million, representing railcar rental for the last half of 2005, were eliminated upon consolidation. The corporate and other results table above includes both sides of this elimination.

General and administrative expenses increased primarily due to changes in director compensation and increased payroll costs as a result of wage increases and new personnel.

Year Ended December 31, 2004, Compared to Year Ended December 31, 2003

Other revenues increased due to increased rail rental income.

Taxes other than income decreased due to a franchise tax adjustment in the first quarter of 2004.

General and administrative expenses decreased primarily due to the absence in 2004 of consulting and advisory fees incurred in 2003 related to the consideration of various shareholder proposals, offset in part by increased payroll costs for new personnel, higher insurance premiums and expenses related to compliance with the Sarbanes-Oxley Act of 2002.

Interest Expense. Interest expense increased from $7.7 million in 2004 to $15.3 million in 2005 primarily due to interest incurred on additional borrowings on the PVR Revolver and a new term loan to finance acquisitions. Seventy-eight percent and 93 percent of our direct Revolver interest costs were capitalized in 2005 and 2004 because the borrowings funded the preparation of unproved properties for their intended use. All direct credit facility interest costs were capitalized during 2003. We capitalized interest costs of $3.5 million, $2.0 million and $2.0 million in 2005, 2004 and 2003.

Unrealized Loss on Derivatives. In 2005, we had a noncash unrealized loss on derivatives of $14.9 million which included a $13.9 million noncash unrealized loss for mark-to-market adjustments on certain derivative agreements, a $0.7

million noncash unrealized loss for mark-to-market adjustments on a natural gas basis swap for which we have elected not to use hedge accounting and a $0.3 million noncash net unrealized loss for changes in effectiveness of open commodity price hedges related to the natural gas midstream segment and the oil and gas segment. The $13.9 million unrealized loss primarily represented the change in the market value of derivative agreements between the time PVR entered into the agreements in January 2005 and the time they qualified for hedge accounting after closing the Cantera Acquisition in March 2005. When PVR agreed to acquire Cantera, management wanted to ensure an acceptable return on the investment. PVR achieved this objective by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a noncash charge to earnings for the unrealized loss on derivatives. Upon qualifying for hedge accounting, changes in the derivative agreements' market value are accounted for as other comprehensive income or loss to the extent they are effective rather than having a direct effect on net income. Cash settlements with the counterparties related to the derivative agreements will occur monthly in the future over the remaining life of the agreements, and PVR will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period.

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.

The operations of the Partnership's coal lessees and natural gas midstream segment 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 coal properties under lease to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of the Partnership's coal lessees and natural gas midstream segment will comply with existing regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2005 and 2004, the Partnership's environmental liabilities included $2.5 million and $1.5 million, which represents PVR's best estimate of the liabilities as of those dates related to the coal and natural gas midstream businesses. The Partnership has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when the reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

See Item 1, "Business—Regulation" for a more detailed discussion of environmental laws and regulations affecting our business.

Recent Accounting Pronouncements

See Note 3 in the Notes to Consolidated Financial Statements for a description of recent accounting pronouncements.

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of

1934, as amended. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the risks set forth in Item 1A, "Risk Factors."

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the SEC. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise.

Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Interest Rate Risk

As of December 31, 2005, we had $79 million of long-term debt outstanding under the Revolver. The Revolver matures in December 2007 and is governed by a borrowing base calculation that is re-determined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.00 percent to 1.75 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 up to 0.50 percent. As a result, our 2006 interest costs will fluctuate based on short-term interest rates relating to our Revolver.

As of December 31, 2005, PVR's $83.0 million of outstanding indebtedness under the Notes carried a fixed interest rate throughout its term. PVR executed an interest rate derivative transaction in March 2003 to effectively convert the interest rate on one-third of the amount outstanding under the Notes from a fixed rate of 5.77 percent to a floating rate of LIBOR plus 2.36 percent. The interest rate swap was accounted for as a fair value hedge in compliance with SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138. The interest rate swap was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by PVR to the counterparty in July 2005.

As of December 31, 2005, PVR's $172.0 million of outstanding indebtedness under the PVR Revolver carried a variable interest rate throughout its term. PVR executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under the PVR Revolver from a LIBOR-based floating rate to a fixed rate of 4.22 percent plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133.

Price Risk Management

Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to seek to mitigate the price risks associated with fluctuations in natural gas and crude oil prices as they relate to our anticipated production. These financial instruments are generally designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 139. 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. See the discussion and table in Note 11 in the Notes to Consolidated Financial Statements for a description of our hedging program and a listing of open derivative agreements and their fair value as of December 31, 2005.

When PVR agreed to acquire Cantera, management wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in an increase in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a $13.9 million noncash charge to earnings for the unrealized loss on these derivatives. Subsequent to the Cantera Acquisition, PVR evaluated the effectiveness of the derivative agreements in relation to the underlying commodities and designated the agreements as cash flow hedges in accordance with SFAS No. 133. Upon qualifying for hedge accounting, changes in the market value of the derivative agreements are accounted for as other comprehensive income or loss to the extent they are effective, rather than as a direct impact on net income. SFAS No. 133 requires the Partnership to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and it will be required to record the ineffective portion of the agreements in net income for the respective period. For 2005, PVR reported a $0.6 million net unrealized gain on derivatives for the ineffective portion of the agreements as of December 31, 2005. Cash settlements with the counterparties to the derivative agreements will occur monthly over the life of the agreements, and PVR will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period. In addition, PVR entered into derivative agreements for NGLs and natural gas to further protect its margins subsequent to the Cantera Acquisition. These derivative agreements have been designated as cash flow hedges. See Note 11 in the Notes to Consolidated Financial Statements for a description of PVR's hedging program and a listing of open derivative agreements and their fair value.

Item 8 ***Financial Statements and Supplementary Data***

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL SECTION

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation, a Virginia corporation, and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 14, 2006, expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
March 14, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting (Item 9A(b)), that Penn Virginia Corporation, a Virginia corporation, and its subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In conducting management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, management has excluded its natural gas midstream business, which was acquired on March 3, 2005 and which now operates as PVR Midstream LLC, as permitted by the Securities and Exchange Commission. PVR Midstream LLC's total assets were $241.9 million, or approximately 19 percent of the Company's total assets, as of December 31, 2005, and PVR Midstream LLC's total revenues were $350.6 million, or approximately 52 percent of the Company's total revenues, for the year ended December 31, 2005. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of PVR Midstream LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2005 and 2004, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005, and our report dated March 14, 2006 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
March 14, 2006

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except share data)

	Year Ended December 31,		
	2005	2004	2003
Revenues			
Natural gas	$ 212,427	$ 138,422	$ 106,615
Oil and condensate	13,792	13,364	16,816
Natural gas midstream	348,657	—	—
Coal royalties	82,725	69,643	50,312
Other	16,263	6,996	7,541
	673,864	228,425	181,284
Expenses			
Cost of gas purchased	303,912	—	—
Operating	32,685	21,773	16,864
Exploration	40,917	26,058	15,589
Taxes other than income	16,005	10,480	11,322
General and administrative	36,606	26,170	24,893
Depreciation, depletion and amortization	76,937	54,952	50,109
Loss on assets held for sale	—	7,541	—
Impairment of oil and gas properties	4,785	655	406
	511,847	147,629	119,183
Operating Income	162,017	80,796	62,101
Other income (expense)			
Interest expense	(15,318)	(7,672)	(5,304)
Interest income and other	1,332	1,101	1,238
Unrealized loss on derivatives	(14,885)	—	—
Income from operations before minority interest, income taxes and cumulative effect of change in accounting principle	133,146	74,225	58,035
Minority interest	30,389	19,023	12,510
Income tax expense	40,669	21,847	18,366
Income from operations before cumulative effect of change in accounting principle	62,088	33,355	27,159
Cumulative effect of change in accounting principle, net of taxes of $734	—	—	1,363
Net Income	$ 62,088	$ 33,355	$ 28,522
Income from operations before cumulative effect of change in accounting principle per share, basic	$ 3.35	$ 1.82	$ 1.51
Cumulative effect of change in accounting principle per share, basic	—	—	0.08
Net income per share, basic	$ 3.35	$ 1.82	$ 1.59
Income from operations before cumulative effect of change in accounting principle per share, diluted	$ 3.31	$ 1.81	$ 1.50
Cumulative effect of change in accounting principle per share, diluted	—	—	0.08
Net income per share, diluted	$ 3.31	$ 1.81	$ 1.58
Weighted average shares outstanding, basic	18,546	18,306	17,976
Weighted average shares outstanding, diluted	18,732	18,467	18,112

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2005	December 31, 2004
Assets		
Current assets		
Cash and cash equivalents	$ 25,913	$ 25,471
Accounts receivable	133,086	40,003
Income taxes receivable	—	4,389
Assets held for sale	—	9,694
Derivative assets	11,551	1,133
Other	7,635	3,549
Total current assets	178,185	84,239
Property and equipment		
Oil and gas properties (successful efforts method)	717,423	591,100
Other property and equipment	538,035	274,191
	1,255,458	865,291
Accumulated depreciation, depletion and amortization	(272,239)	(199,803)
Net property and equipment	983,219	665,488
Equity investments	26,672	27,881
Goodwill	7,718	—
Intangibles, net	38,051	—
Derivative assets	8,917	225
Other assets	8,784	5,502
Total assets	$ 1,251,546	$ 783,335
Liabilities and Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$8,108	$4,800
Accounts payable	71,429	8,899
Accrued liabilities	43,249	26,353
Derivative liabilities	29,387	1,723
Income taxes payable	2,355	—
Total current liabilities	154,528	41,775
Other liabilities	24,448	18,095
Derivative liabilities	11,706	876
Deferred income taxes	111,186	97,912
Long-term debt of the Company	79,000	76,000
Long-term debt of PVR	246,846	112,926
Minority interest in PVR	313,524	182,891
Commitments and contingencies (Note 22)		
Shareholders' equity		
Preferred stock of $100 par value—100 authorized shares; none issued	—	—
Common stock of $0.01 par value – 32,000 shares authorized; 18,624 and 18,476 shares issued and outstanding at December 31, 2005 and 2004	186	185
Paid-in capital	98,541	85,543
Retained earnings	222,456	168,726
Deferred compensation obligation	580	—
Accumulated other comprehensive income	(7,816)	(720)
Treasury stock—13 shares common stock, at cost, on December 31, 2005	(832)	—
Unearned compensation	(2,807)	(874)
Total shareholders' equity	310,308	252,860
Total liabilities and shareholders' equity	$ 1,251,546	$ 783,335

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS’ EQUITY AND COMPREHENSIVE INCOME
(in thousands)

	Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation Obligation	Accumulated Other Comprehensive Income	Treasury Stock	Unearned Compensation and ESOP	Total Shareholders’ Equity	Comprehensive Income (Loss)
Balance at December 31, 2002	17,893	$ 55,915	$ 11,436	$ 123,189	$ —	$ (1,661)	$ —	$ (923)	$ 187,956	
Dividends paid ($0.45 per share)	—	—	—	(8,092)	—	—	—	—	(8,092)	
Stock issued as compensation	14	42	229	—	—	—	—	—	271	
PVR units issued as compensation, net	—	—	172	—	—	—	—	(71)	101	
Exercise of stock options	198	619	2,364	—	—	—	—	—	2,983	
Allocation of ESOP shares	—	—	296	—	—	—	—	200	496	
Net income	—	—	—	28,522	—	—	—	—	28,522	$ 28,522
Other comprehensive loss, net of tax	—	—	—	—	—	(589)	—	—	(589)	(589)
Balance at December 31, 2003	18,105	56,576	14,497	143,619	—	(2,250)	—	(794)	211,648	$ 27,933
Dividends paid ($0.45 per share)	—	—	—	(8,248)	—	—	—	—	(8,248)	
Recognition of gain on conversion of subordinated PVR units to common	—	—	6,393	—	—	—	—	—	6,393	
Stock issued as compensation	7	—	239	—	—	—	—	—	239	
PVR units issued as compensation, net	—	—	440	—	—	—	—	(139)	301	
Vesting of restricted units	—	—	(354)	—	—	—	—	—	(354)	
Exercise of stock options	364	4	7,814	—	—	—	—	—	7,818	
Allocation of ESOP shares	—	—	119	—	—	—	—	59	178	
Change in par value	—	(56,395)	56,395	—	—	—	—	—	—	
Net income	—	—	—	33,355	—	—	—	—	33,355	$ 33,355
Other comprehensive gain, net of tax	—	—	—	—	—	1,530	—	—	1,530	1,530
Balance at December 31, 2004	18,476	185	85,543	168,726	—	(720)	—	(874)	252,860	$ 34,885
Dividends paid ($0.45 per share)	—	—	—	(8,358)	—	—	—	—	(8,358)	
Recognition of gain on conversion of subordinated PVR units to common	—	—	6,393	—	—	—	—	—	6,393	
Stock issued as compensation	29	—	1,656	—	—	—	—	(1,507)	149	
PVR units issued as compensation, net	—	—	1,123	—	—	—	—	(426)	697	
Vesting of restricted units	—	—	(315)	—	—	—	—	—	(315)	
Exercise of stock options	119	1	3,561	—	—	—	—	—	3,562	
Issuance of 24 thousand shares to deferred compensation plans	—	—	580	—	580	—	(832)	—	328	
Net income	—	—	—	62,088	—	—	—	—	62,088	$ 62,088
Other comprehensive loss, net of tax	—	—	—	—	—	(7,096)	—	—	(7,096)	(7,096)
Balance at December 31, 2005	18,624	$ 186	$ 98,541	$ 222,456	$ 580	$ (7,816)	$ (832)	$ (2,807)	$ 310,308	$ 54,992

See accompanying notes to consolidated financial statements

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 2005	2004	2003
Cash flows from operating activities			
Net income	$ 62,088	$ 33,355	$ 28,522
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	76,937	54,952	50,109
Unrealized loss on derivatives	14,885	—	—
Deferred income taxes	17,094	19,225	15,292
Minority interest	30,389	19,023	12,510
Dry hole and unproved leasehold expense	29,736	16,010	5,989
Impairment of oil and gas properties	4,785	655	406
Loss on assets held for sale	—	7,541	—
Cumulative effect of change in accounting principle	—	—	(1,363)
Other	5,989	5,229	2,282
Changes in operating assets and liabilities:			
Accounts receivable	(52,671)	(12,603)	(11,423)
Other current assets	(876)	(1,781)	239
Accounts payable and accrued liabilities	43,475	2,996	4,785
Other assets and liabilities	(424)	1,763	2,356
Net cash flows provided by operating activities	231,407	146,365	109,704
Cash flows from investing activities			
Proceeds from the sale of property and equipment	17,385	1,559	850
Acquisitions, net of cash acquired	(290,938)	(28,442)	—
Additions to property and equipment	(184,386)	(125,241)	(128,182)
Other	—	767	530
Net cash flows used in investing activities	(457,939)	(151,357)	(126,802)
Cash flows from financing activities			
Dividends paid	(8,358)	(8,248)	(8,092)
Distributions paid to minority interest holders of PVR	(30,737)	(21,892)	(19,880)
Proceeds from issuance of PVR partners' capital	126,456	—	—
Proceeds from borrowings of the Company	78,000	33,000	108,398
Repayment of borrowings of the Company	(75,000)	(21,000)	(60,450)
Proceeds from PVR borrowings	288,800	28,500	90,000
Repayments of PVR borrowings	(151,600)	(2,500)	(88,387)
Payments for debt issuance costs	(2,835)	(1,234)	(2,824)
Issuance of stock and other	2,248	5,829	3,000
Net cash flows provided by financing activities	226,974	12,455	21,765
Net increase in cash and cash equivalents	442	7,463	4,667
Cash and cash equivalents—beginning of year	25,471	18,008	13,341
Cash and cash equivalents—end of year	$ 25,913	$ 25,471	$ 18,008
Supplemental disclosures:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 12,978	$ 5,790	$ 3,810
Income taxes	$ 15,455	$ 4,148	$ 6,529
Noncash investing and financing activities:			
Issuance of PVR units for acquisitions	$ 10,415	$ 1,060	$ 4,969
Assumption of liabilities in acquisitions	$ 3,981	$ —	$ —

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent energy company that is engaged in three primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal segment and natural gas midstream segment operate through our 39 percent ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"). Due to our control of the general partner of PVR, the financial results of the Partnership are included in our consolidated financial statements. However, PVR functions with a capital structure that is independent of the Company, consisting of its own debt instruments and publicly traded common units.

In the coal segment, PVR does not operate any mines. Instead, PVR enters into leases with various third-party operators which give those operators the right to mine coal reserves on PVR's land in exchange for royalty payments. PVR also provides fee-based infrastructure facilities to some of its lessees and third parties to generate coal services revenues. These facilities include coal loading facilities, preparation plants and coal handling facilities located at end-user industrial plants. PVR also sells timber growing on its land.

PVR purchased its midstream business on March 3, 2005, through the acquisition of Cantera Gas Resources, LLC (see Note 4). As a result of this acquisition, PVR owns and operates a significant set of midstream assets. PVR's midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services.

2. Penn Virginia Resource Partners, L.P.

Penn Virginia Resource Partners, L.P. is a Delaware limited partnership formed by Penn Virginia in July 2001 primarily to engage in the business of managing coal properties in the United States. The Partnership completed an initial public offering (the "IPO") in October 2001. Effective with the closing of the IPO, Penn Virginia, through its wholly owned subsidiaries, received common and subordinated units and a two percent general partnership interest in the ownership of the Partnership. The general partner of the Partnership is Penn Virginia Resource, GP, LLC, a wholly owned subsidiary of 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 IPO units as a sale of a minority interest. At the time of the IPO, we computed a gain of $25.6 million under SEC Staff Accounting Bulletin Topic 5-H, *Accounting for Sales of Stock by a Subsidiary*, which is included in minority interest. As our subordinated units convert to common units, we recognize the gain calculated at the time of the IPO as paid-in capital. All subordinated units will convert to common units after September 30, 2006, if certain criteria are met. In November 2004, 25 percent of the subordinated units converted to common units, and another 25 percent converted in November 2005, as the Partnership met certain requirements to qualify for early conversion. In each of the years 2005 and 2004, $6.4 million of the $25.6 million gain were reclassified from minority interest to paid-in capital upon the conversion of the subordinated units, for a cumulative reclassification of $12.8 million as of December 31, 2005.

In March 2005, PVR issued 2.5 million common units in a public offering, which constitutes a sale of a minority interest from our perspective. We also issued common units in connection with an acquisition in 2005 (see Note 4). We will recognize an additional gain resulting from the March 2005 public offering and issuance of units in the acquisition when the final tranche of subordinated units converts to common units. At that time, the gain will be reclassified from minority interest to paid-in capital.

3. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Penn Virginia, all wholly-owned subsidiaries of the Company and the Partnership, of which we indirectly owned the sole two percent general partner interest and an approximately 37 percent limited partner interest as of December 31, 2005. Penn Virginia Resource GP, LLC, a wholly-owned subsidiary of Penn Virginia, serves as the Partnership's 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

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. As of December 31, 2005, we had capitalized $1.7 million of exploratory drilling costs related to three exploratory wells which reached total depth in 2005 but were under evaluation for commercial viability.

The following table describes the changes in capitalized exploratory drilling costs that are pending the determination of proved reserves (in thousands, except wells):

	2005		2004		2003	
	# Wells	Cost	# Wells	Cost	# Wells	Cost
Balance at beginning of period	3	$ 3,079	10	$ 3,785	—	$ —
Additions pending determination of proved reserves	3	1,670	3	3,079	10	3,785
Reclassifications to wells, equipment and facilities based on the determination of proved reserves	—	—	—	—	—	—
Charged to expense	(3)	(3,079)	(10)	(3,785)	—	—
Balance at end of period	3	$ 1,670	3	$ 3,079	10	$ 3,785

We had no capitalized exploratory drilling costs that had been under evaluation for a period greater than one year as of December 31, 2005, 2004 or 2003.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. Interest costs associated with non-producing leases were capitalized in the amounts of $3.5 million, $2.0 million and $2.0 million in 2005, 2004 and 2003. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are significant. Unproved properties whose acquisition costs are not significant are amortized in the aggregate over the lesser of five years or the average remaining lease term. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results. As of December 31, 2005 and 2004, unproved leasehold costs amounted to $66.7 million and $61.0 million.

Asset Retirement Obligations

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations,* we recognize the fair value of a liability for an asset retirement obligation (an "ARO") in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. See Note 13, "Asset Retirement Obligations." The amount of an ARO and the costs capitalized equal the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using an assumed cost of funds for us. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the additional capitalized costs will be depreciated over the productive life of the assets. Both the accretion and the depreciation are included in depreciation, depletion and amortization on our consolidated statements of income.

We identified all required asset retirement obligations and determined the fair value of these obligations on January 1, 2003, 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, we recorded a cumulative effect of change in accounting principle, net of taxes, of approximately $1.4 million as an increase to income in 2003. We recorded an additional liability of $0.6 million as of December 31, 2005, upon adoption of Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations,* relating to our natural gas midstream segment.

Other Property and Equipment

Other property and equipment consist of PVR's ownership in coal fee mineral interests, PVR's royalty interest in oil and natural gas wells, processing facilities, gathering systems, compressor stations and related equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. We compute depreciation and amortization of property and equipment using the straight-line or declining balance method over the estimated useful life of each asset as follows:

	Useful Life
Gathering systems	15 years
Compressor stations	5-15 years
Processing plants	15 years
Other property and equipment	3-20 years

We deplete coal properties on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. From time to time, PVR carries out core-hole drilling activities on coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-drilling activities are expensed as incurred. When we retire or sell an asset, we remove its cost and related accumulated depreciation and amortization from the balance sheet. We record the difference between the net book value (net of any related asset retirement obligation) and proceeds from disposition as gain or loss.

Impairment of Long-Lived Assets

We review long-lived assets to be held and used whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. We recognize an impairment loss when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we 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 present value of future net cash flows from proved reserves, discounted utilizing a rate commensurate with the risk and remaining lives for the respective oil and gas properties.

Equity Investments

We use the equity method of accounting to account for the Partnership's investment in a coal handling joint venture, recording the initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect the Partnership's share of income of the investee and is reduced to reflect the Partnership's share of losses of the investee or distributions received from the investee as the joint venture reports them. The Partnership's share of earnings or losses from the investment is included in other revenues on the consolidated statements of income. Other revenues also include amortization of the amount of PVR's equity investment that exceeds its portion of the underlying equity in net assets. PVR records amortization over the life of coal services contracts in place at the time of the Partnership's initial investment.

Goodwill

We had approximately $7.7 million of goodwill at December 31, 2005, based on the preliminary purchase price allocation for the Cantera Acquisition (as defined in Note 4). This amount may change based on the final purchase price allocation. The goodwill has been allocated to the midstream segment. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets,* goodwill will be assessed at least annually for impairment. We tested goodwill for impairment during the fourth quarter of 2005 and determined that no impairment charge was necessary.

Intangibles

Intangible assets at December 31, 2005, included $37.7 million for customer contracts and relationships acquired in the Cantera Acquisition (see Note 4) and the Alloy Acquisition (see Note 5) and $4.6 million for rights-of-way acquired in the Cantera Acquisition (see Note 4). These amounts may change based on the final Cantera Acquisition purchase price allocation as described in Note 4. Customer contracts and relationships are amortized on a straight-line basis over the expected useful lives of the individual contracts and relationships, up to 15 years. Rights-of-way are amortized on a straight-line basis over a period of 15 years. Aggregate amortization expense was $4.2 million in 2005, and there were no intangible assets or related amortization in 2004 or 2003. As of December 31, 2005, accumulated amortization of intangible assets was $4.2 million.

The following table summarizes our estimated aggregate amortization expense for the next five years (in thousands):

2006	$ 5,006
2007	4,106
2008	3,485
2009	3,219
2010	3,006
Thereafter	19,229
Total	$ 38,051

Concentration of Credit Risk

Approximately 43 percent of consolidated accounts receivable at December 31, 2005, resulted from oil and gas sales and joint interest billings to third party companies in the oil and gas industry. Approximately 48 percent resulted from natural gas midstream customers, and the remaining nine percent resulted from accrued revenues from the Partnership's lessee production. This concentration of customers, joint interest owners and lessees 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, joint interest owner or lessee, we analyze the entity's net worth, cash flows, earnings and credit ratings to the extent information is available. Receivables are generally not collateralized. Historical credit losses incurred on receivables have not been significant.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments and long-term debt. The carrying values of all of these financial instruments, except for PVR's fixed rate long-term debt, approximate fair value. The fair value of PVR's fixed rate long-term debt at December 31, 2005 and 2004, was $81.2 million and $86.2 million.

Revenues

Oil and Gas Revenues. Revenues associated with sales of natural gas, crude oil, condensate and natural gas liquids are recorded when title passes to the customer. Natural gas sales revenues from properties in which we have an interest with other producers are recognized on the basis of our net working interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. Any amount received in excess of our share is treated as deferred revenues. If we take less than we are entitled to take, the under-delivery is recorded as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, accruals for revenues and accounts receivable are made based on estimates of our share of production, particularly from properties that are operated by our partners. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Natural Gas Midstream Revenues. Revenues from the sale of natural gas liquids ("NGLs") and residue gas are recognized when PVR sells the NGLs and residue gas produced at its gas processing plants. We recognize gathering and transportation revenues based upon actual volumes delivered. Due to the time needed to gather information from various purchasers and measurement locations and then calculate volumes delivered, the collection of natural gas midstream revenues may take up to 30 days following the month of production. Therefore, we make accruals for revenues and accounts receivable and the related cost of gas purchased and accounts payable based on estimates of natural gas purchased and NGLs and residue gas sold, and our financial results include estimates of production and revenues for the period of actual production. We record any differences, which have not historically been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenues from those sales. Most of the Partnership's coal leases are based on minimum monthly or annual rental payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price. The remainder of PVR's coal royalty revenues was derived from fixed royalty rate leases, which escalate annually, with pre-established minimum monthly payments. Coal royalty revenues are accrued on a monthly basis, based on PVR's best estimates of coal mined on its properties.

Coal Services. Coal services revenues are recognized when lessees use the Partnership's facilities for the processing, loading and/or 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 plants and dock loading facility. Coal services revenues are included in other revenues on the consolidated statements of income.

Equity Earnings. The Partnership recognizes its share of income or losses from its investment in a coal handling joint venture as the joint venture reports them to the Partnership. Equity earnings are included in other revenues.

Minimum Rentals. Most of the Partnership's lessees are required to 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 deferred income attributable to the minimum payment is recognized as minimum rental revenues and is included in other revenues.

Hedging Activities

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas, crude oil and NGL 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, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149 and related interpretations.

All derivative instruments are recorded on the balance sheet at fair value. The fair values of our hedging instruments are determined based on third party forward price quotes. 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 utilize only cash flow hedges, and the remaining discussion relates exclusively to this type of derivative instrument. All hedge transactions are subject to our risk management policy, which has been reviewed and approved by our Board of Directors.

We formally document all relationships between hedging instruments and hedged items, as well as the 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 periodic basis. If we were to determine that a derivative were not highly effective as a hedge, or that it had ceased to be highly effective, then we would discontinue hedge accounting prospectively.

If hedge accounting is discontinued and the derivative remains outstanding, we will carry the derivative at its fair value on our consolidated balance sheet and recognize all subsequent changes in fair value on our consolidated statement of income for the period in which the change occurs. Gains and losses deferred in other comprehensive income related to cash flow hedges for which hedge accounting has been discontinued remain in other comprehensive income until the related product has been delivered. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Gains and losses on hedging instruments when settled are included in natural gas revenues, oil and condensate revenues, natural gas midstream revenues or cost of gas purchased in the period that the related production is delivered.

Income Tax

We account for income taxes in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes*, which 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 19). We account for those plans under the recognition and measurement principles of Accounting Principles Board 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 as 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, except per share data).

	Year ended December 31,		
	2005	**2004**	**2003**
Net income, as reported	$ 62,088	$ 33,355	$ 28,522
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	1,008	435	332
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,751)	(1,022)	(1,119)
Pro forma net income	$ 61,345	$ 32,768	$ 27,735
Earnings per share			
Basic—as reported	$ 3.35	$ 1.82	$ 1.59
Basic—pro forma	$ 3.31	$ 1.79	$ 1.55
Diluted—as reported	$ 3.31	$ 1.81	$ 1.58
Diluted—pro forma	$ 3.27	$ 1.77	$ 1.53

New Accounting Standards

In December 2004, the Financial Accounting Standards Board (the "FASB") issued the final revised version of SFAS No. 123R, *Share-Based Payment,* which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. In March 2005, the SEC issued Staff Accounting Bulletin ("SAB") No. 107, *Share-Based Payment,* regarding the interaction between SFAS No. 123R and certain SEC rules and regulations. We will adopt SFAS No. 123R and SAB No. 107 effective January 1, 2006. At that time, we will begin to recognize compensation expense for new grants as well as the unvested portion of then outstanding options. Expense will be recognized over the requisite vesting period. We expect that stock option grants will continue to be a significant part of employee compensation, and therefore, SFAS No. 123R will have a significant impact on our financial statements with the prospective adoption of this accounting method in January 2006. Although we have not determined the impact of SFAS No. 123R, compensation expense relating to stock options will increase.

In March 2005, the FASB released Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"), which provides guidance for applying SFAS No. 143. FIN 47 became effective as of December 31, 2005, and we recorded an additional liability of $0.6 million as a result of implementing FIN 47, relating to our natural gas midstream segment. The cumulative effect of change in accounting principle of $0.1 million was not material and was included in depreciation, depletion and amortization expense in the statement of income.

In April 2005, the FASB issued FASB Staff Position No. FAS 19-1 (the "FSP") to amend the guidance for suspended well costs in SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.* The FSP addresses circumstances that permit the continued capitalization of exploratory well costs beyond one year. Essentially, exploratory drilling costs may continue to be capitalized beyond one year if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. We adopted the FSP on July 1, 2005. The adoption of the FSP has not had a material effect on our consolidated results of operations or financial position.

In June 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statement No. 3,* which replaces Accounting Principles Board Opinion No. 20, *Accounting Changes,* and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements,* and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application for voluntary changes in accounting principle unless it is impracticable to do so, and it applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Consequently, we will adopt the provisions of SFAS 154 for our fiscal year beginning January 1, 2006. We expect that adoption of the provisions of SFAS No. 154 will not have a material impact on our consolidated financial statements.

In June 2005, the EITF reached a consensus on EITF Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.* This consensus applies to voting right entities not within the scope of FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities,* in which the investor is the general partner in a limited partnership or functional equivalent. The EITF consensus is that the general partner in a limited partnership is presumed to control that limited partnership regardless of the extent of the general partner's ownership interest and, therefore, should include the limited partnership in its consolidated financial statements. The general partner may overcome this presumption of control and not consolidate the entity if the limited partners have either: (a) the substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner through substantive kick-out rights that can be exercised without having to show cause; or (b) substantive participating rights in managing the partnership. This guidance became immediately effective upon ratification by the FASB on June 29, 2005, for all newly formed limited partnerships and for existing limited partnerships for which the partnership agreements have been modified. For general partners in all other limited partnerships, the guidance is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We currently consolidate PVR, and the adoption of EITF Issue No. 04-5 will not change our consolidation method with respect to PVR.

4. Acquisition of Natural Gas Midstream Business

On March 3, 2005, PVR completed the acquisition (the "Cantera Acquisition") of Cantera Gas Resources, LLC ("Cantera"), a midstream gas gathering and processing company with primary locations in Oklahoma and Texas. The midstream business operates as PVR Midstream LLC, a subsidiary of Penn Virginia Operating Co., LLC, which is a wholly owned subsidiary of the Partnership. As a result of the Cantera Acquisition, PVR owns and operates a significant set of midstream assets including gas gathering pipelines and three natural gas processing facilities. The midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. The results of operations of PVR Midstream LLC since March 3, 2005, the closing date of the Cantera Acquisition, are included in the accompanying consolidated statements of income.

Cash paid in connection with the Cantera Acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which PVR funded with a $110 million term loan and with borrowings under the Partnership's revolving credit facility. The purchase price allocation for the Cantera Acquisition has been finalized except for the settlement of certain post-closing adjustments with the seller. PVR used proceeds of $126.4 million from PVR's sale of common units in a subsequent public offering in March 2005 and a $2.6 million contribution from the general partner to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Cantera Acquisition based upon preliminary fair values on the date of acquisition as follows (in thousands):

Cash consideration paid for Cantera	$ 201,326
Plus: Acquisition costs	3,275
Total purchase price	204,601
Less: Cash acquired	(5,378)
Total purchase price, net of cash acquired	$ 199,223
Current assets acquired	$ 43,697
Property and equipment acquired	145,448
Other assets acquired	645
Liabilities assumed	(38,337)
Intangible assets	40,052
Goodwill	7,718
Total purchase price, net of cash acquired	$ 199,223

The preliminary purchase price allocation includes approximately $7.7 million of goodwill. The significant factors that contributed to the recognition of goodwill include PVR's entry into the natural gas midstream business and PVR's ability to acquire an established business with an assembled workforce.

Under SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill recorded in connection with a business combination is not amortized, but rather is tested for impairment at least annually. Accordingly, the unaudited pro forma financial information presented below does not include amortization of the goodwill recorded in the Cantera Acquisition. The preliminary purchase price allocation also includes $40.1 million of intangible assets that are primarily associated with assumed customer contracts, customer relationships and rights of way. These intangible assets are being amortized over periods of up to 15 years, the period in which benefits are derived from the contracts, relationships and rights-of-way assumed, and are reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

The following unaudited pro forma financial information reflects our consolidated results of operations as if the Cantera Acquisition and related debt and equity financings had occurred on January 1 of the reported period. The pro forma information includes adjustments primarily for depreciation of acquired property and equipment, amortization of intangibles and interest expense for acquisition debt. The pro forma financial information is not necessarily indicative of the results of operations as it would have been had these transactions been effected on the assumed date (in thousands, except share data).

	Year Ended December 31, 2005	Year Ended December 31, 2004
Revenues	$ 692,228	$ 299,950
Net income	$ 62,179	$ 36,177
Net income per share, basic	$ 3.35	$ 1.98
Net income per share, diluted	$ 3.32	$ 1.96

5. Other Acquisitions

In the following paragraphs, all references to coal, oil and natural gas reserves and acreage acquired are unaudited.

Oil and Gas Segment

In June 2005, we acquired approximately 60,000 acres of prospective CBM leasehold rights in Wyoming County, West Virginia from Panther Energy Company, LLC for $13.3 million in cash (the "Panther Acquisition"). The leasehold acreage is within an area of mutual interest between Penn Virginia and CDX Gas, LLC ("CDX") and is contiguous to acreage which has been successfully developed. The purchase agreement included an option for CDX to purchase a 50 percent interest in the leasehold acreage. In August 2005, CDX exercised that option and acquired its 50 percent interest for $6.6 million in cash. We began drilling on the new leasehold position in the fourth quarter of 2005.

PVR Coal Segment

In March 2005, PVR acquired lease rights to approximately 36 million tons of undeveloped coal reserves and royalty interests in 73 producing oil and natural gas wells for $9.3 million in cash (the "Coal River Acquisition"). The coal reserves are located in the central Appalachia region of southern West Virginia. The oil and gas wells are located in eastern Kentucky and southwestern Virginia. The Coal River Acquisition was funded with long-term debt under PVR's revolving credit facility. The coal reserves are predominantly low sulfur and high BTU content, and development will occur in conjunction with PVR's adjacent reserves and a related loadout facility that was placed into service in 2004. The oil and gas property contains approximately 2.8 billion cubic feet equivalent ("Bcfe") of net proved oil and gas reserves.

In April 2005, PVR acquired fee ownership of approximately 16 million tons of coal reserves for $15.0 million in cash (the "Alloy Acquisition"). The reserves, located on approximately 8,300 acres in the central Appalachia region of West Virginia, will be produced from deep and surface mines. Production started in late 2005. Revenues were earned initially from transportation-related fees on coal mined from an adjacent property, followed by royalty revenues as the mines on PVR's property commenced production. The seller remained on the property as the lessee and operator. The Alloy Acquisition was funded with long-term debt under PVR's revolving credit facility.

In July 2005, PVR acquired a combination of fee ownership and lease rights to approximately 16 million tons of coal reserves for $14.5 million (the "Wayland Acquisition"). The reserves are located in the eastern Kentucky portion of central Appalachia. The Wayland Acquisition was funded with $4 million of cash and the issuance by PVR to the seller of approximately 209,000 PVR common units. In addition, PVR assumed $0.7 million of liabilities related to the acquired property.

In July 2005, PVR also acquired fee ownership of approximately 94 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for $62.4 million in cash (the "Green River Acquisition"), and PVR assumed $3.3 million of deferred income. This coal reserve acquisition is PVR's first in the Illinois Basin and was funded with long-term debt under PVR's revolving credit facility. Currently, approximately 43 million tons of these coal reserves are leased to affiliates of Peabody Energy Corporation (NYSE: BTU) ("Peabody").

In July 2004, the Partnership acquired from affiliates of Massey Energy Company a 50 percent interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was $28.4 million and was funded with long-term debt under the Partnership's revolving credit facility. The joint venture owns coal handling facilities which unload coal shipments and store and transfer coal for three industrial coal consumers in the chemical, paper and lime production industries located in Tennessee, Virginia and Kentucky. A combination of fixed monthly fees and per ton throughput fees is paid by those consumers under long-term leases expiring between 2007 and 2019.

In December 2002, the Partnership acquired two properties containing approximately 120 million tons of coal reserves from affiliates of 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 plus closing costs (the "Peabody Acquisition"). In July 2003, all of the class B common units were converted to common units, in accordance with their terms, upon the approval of the Partnership's common unitholders. All of the coal reserves we purchased from Peabody are being leased back to Peabody for fixed royalty rates which escalate annually over the life of production. The acquired coal reserves had existing productive operations that have been included in the Partnership's statements of income since the closing date of the Peabody Acquisition.

The factors used 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 lessees.

6. Sale of Texas Properties

On January 24, 2005, we completed the sale of certain oil and gas properties in Texas for cash proceeds of $9.7 million. These properties were classified as assets held for sale on the consolidated balance sheet as of December 31, 2004. As part of the sale agreement, we will receive a 20 percent net profits interest in one of the properties beginning January 1, 2006. In addition, the buyer has agreed to perform a waterflood technique on this property. If the buyer fails to complete the waterflood technique within specified deadlines, then under certain conditions the buyer would be liable to pay us additional proceeds of $0.5 million.

7. Stock Split and Change in Par Value

On May 4, 2004, the Board of Directors approved a two-for-one split of the Company's common stock in the form of a 100 percent stock dividend payable on June 10, 2004, to shareholders of record on June 3, 2004. Shareholders received one additional share of common stock for each share held on the record date. All common shares and per share data have been retroactively adjusted to reflect the stock split. Also effective June 10, 2004, the Company changed the par value of its common stock from $6.25 to $0.01 per share.

8. Property and Equipment

Property and equipment includes (in thousands):

	December 31, 2005	December 31, 2004
Oil and gas properties		
Proved	$ 650,696	$ 530,087
Unproved	66,727	61,013
Total oil and gas properties	717,423	591,100
Other property and equipment:		
Coal properties	340,439	251,244
Midstream property and equipment	151,154	—
Other property and equipment	35,767	21,150
Land	10,675	1,797
Total property and equipment	1,255,458	865,291
Accumulated depreciation, depletion and amortization	(272,239)	(199,803)
Net property and equipment	$ 983,219	$ 665,488

9. Impairment of Oil and Gas Properties

In accordance with SFAS No. 144, 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 or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. When we find that the carrying amounts of the properties exceed their estimated undiscounted future cash flows, we adjust the carrying amounts of the properties to their fair value as determined by discounting their estimated future cash flows. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

For the year ended December 31, 2005, we recognized a pretax charge of $4.8 million related to the impairment of certain properties in Texas. This impairment was a result of downward reserve revisions on the properties.

For the year ended December 31, 2004, we recognized a pretax charge of $0.7 million related to the impairment of certain West Virginia horizontal coalbed methane (“CBM”) properties. This impairment was associated with a CBM well completed in 2004 in northern West Virginia that had insufficient natural gas reserves to support the historical cost basis of the property.

For the year ended December 31, 2003, we recognized a pretax charge of $0.4 million related to the impairment of certain south Texas properties. These impairments were a result of downward reserve revisions on these properties caused by the poor performance of these wells near the end of their productive lives.

10. Equity Investments

As described in Note 5, “Other Acquisitions,” the Partnership acquired a 50 percent interest in Coal Handling Solutions, LLC, a joint venture formed to own and operate end-user coal handling facilities. The Partnership accounts for the investment under the equity method of accounting. In 2004, the original cash investment of $28.4 million was capitalized. At December 31, 2005, the Partnership’s equity investment totaled $26.6 million, which exceeded its portion of the underlying equity in net assets by $10.7 million. The difference is being amortized to equity earnings over the life of coal services contracts in place at the time of the acquisition. In accordance with the equity method, the Partnership recognized equity earnings of $1.1 million in 2005 and $0.4 million in 2004 with a corresponding increase in the investment. The joint venture generally pays to PVR quarterly distributions of PVR’s portion of the joint venture’s cash flows. PVR received cash distributions of approximately $2.3 million and $1.0 million in 2005 and 2004. Equity earnings are included in other revenues on the consolidated statements of income.

11. Hedging Activities

Commodity Cash Flow Hedges

Oil and Gas Segment. The fair values of our oil and gas derivative contracts are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of December 31, 2005. The following table sets forth our positions as of December 31, 2005:

	Average Volume Per Day	Weighted Average Price Collars		Estimated Fair Value (in thousands)
		Floor	Ceiling	
Natural Gas Costless Collars	**(in Mmbtus)**	**(per Mmbtu)**		
First Quarter 2006	36,344	$ 7.12	$ 12.07	$ (3,961)
Second Quarter 2006	28,330	$ 6.94	$ 11.81	(1,437)
Third Quarter 2006	22,000	$ 7.82	$ 12.25	(1,100)
Fourth Quarter 2006	20,011	$ 8.23	$ 15.32	(637)
First Quarter 2007	15,000	$ 9.00	$ 19.20	381
Second Quarter 2007	10,000	$ 7.00	$ 12.65	(164)
Third Quarter 2007	10,000	$ 7.00	$ 12.65	(204)
Fourth Quarter 2007 (October only)	10,000	$ 7.00	$ 12.65	(93)
Crude Oil Costless Collars	**(in Bbls)**	**(per Bbl)**		
First Quarter 2006 (January and February only)	200	$ 42.00	$ 47.75	(236)
Total				$ (7,451)

Based upon our assessment of our derivative agreements designated as cash flow hedges at December 31, 2005, we reported (i) a net derivative liability of approximately $7.5 million, (ii) a loss in accumulated other comprehensive income of $4.2 million, net of a related income tax benefit of $2.3 million and (iii) an unrealized loss on derivatives for hedge ineffectiveness of $0.9 million related to cash flow hedges in the oil and gas segment. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $14.9 million for the year ended December 31, 2005. Based upon future oil and natural gas prices as of December 31, 2005, we expect to realize $7.4 million of hedging losses within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. We recognized net hedging losses of $5.9 million and $6.1 million for each of the years ended December 31, 2004 and 2003.

In January 2006, we entered into an additional crude oil costless collar for 200 barrels per day, effective March 2006 through December 2007, at a floor price of $60.00 per barrel and a ceiling price of $72.20 per barrel.

Natural Gas Midstream Segment. When PVR agreed to acquire Cantera, management wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a $13.9 million noncash charge to earnings during the first quarter of 2005 for the unrealized loss on derivatives. Subsequent to the Cantera Acquisition, PVR formally designated the agreements as cash flow hedges in accordance with SFAS No. 133. Upon qualifying for hedge accounting, changes in the derivative agreements' market value are accounted for as other comprehensive income or loss to the extent they are effective, rather than as a direct impact on net income. SFAS No. 133 requires the Partnership to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and it is required to record the ineffective portion of the agreements in net income for the respective period. Cash settlements with the counterparties related to the derivative agreements will occur monthly over the life of the agreements, and PVR will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period. In addition, PVR entered into derivative agreements for NGLs and natural gas to further protect its margins subsequent to the Cantera Acquisition. These derivative agreements have been designated as cash flow hedges.

The fair values of PVR's derivative agreements are determined based on forward price quotes for the respective commodities as of December 31, 2005. The following table sets forth PVR's positions as of December 31, 2005, for commodities related to natural gas midstream revenues (ethane, propane and crude oil) and cost of gas purchased (natural gas):

	Average Volume Per Day	Weighted Average Price	Estimated Fair Value (in thousands)
Ethane Swaps	**(in gallons)**	**(per gallon)**	
First Quarter 2006 through Fourth Quarter 2006	68,880	$ 0.4770	$ (6,269)
First Quarter 2007 through Fourth Quarter 2007	34,440	$ 0.5050	(1,839)
First Quarter 2008 through Fourth Quarter 2008	34,440	$ 0.4700	(1,442)
Propane Swaps	**(in gallons)**	**(per gallon)**	
First Quarter 2006 through Fourth Quarter 2006	52,080	$ 0.7060	(5,918)
First Quarter 2007 through Fourth Quarter 2007	26,040	$ 0.7550	(1,679)
First Quarter 2008 through Fourth Quarter 2008	26,040	$ 0.7175	(1,471)
Crude Oil Swaps	**(in Bbls)**	**(per Bbl)**	
First Quarter 2006 through Fourth Quarter 2006	1,100	$ 44.45	(7,834)
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(2,501)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(2,313)
Natural Gas Swaps	**(in MMbtu)**	**(per MMbtu)**	
First Quarter 2006 through Fourth Quarter 2006	7,500	$ 7.05	9,940
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	4,474
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	3,126
			$ (13,726)

Based upon the assessment of derivative agreements designated as cash flow hedges at December 31, 2005, PVR reported (i) a net derivative liability related to the natural gas midstream segment of $13.7 million, (ii) a loss in accumulated other comprehensive income of $4.0 million, net of a related income tax benefit of $2.1 million and (iii) a net unrealized gain on derivatives for hedge ineffectiveness of $0.6 million for the year ended December 31, 2005 related to cash flow hedges in the natural gas midstream segment. In connection with monthly settlements, PVR recognized net hedging losses in natural gas midstream revenues of $3.9 million for the year ended December 31, 2005, and net hedging gains in cost of gas purchased of $4.9 million for the year ended December 31, 2005. Based upon future commodity prices as of December 31, 2005, PVR expects to realize $10.1 million of hedging losses within the next 12 months. The amounts that PVR will ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. Because all hedged volumes relate to periods beginning after March 31, 2005, PVR had no monthly settlements and recognized no net hedging losses in natural gas midstream revenues in 2004.

In November 2005, PVR entered into a basis swap for the period January 2006 through July 2006. The basis swap relates to purchases of natural gas in the Texas/Oklahoma Basin region. We have chosen not to designate this derivative as a hedge pursuant to SFAS No. 133, as amended. Therefore, changes in market value of the derivative instrument are charged to earnings. At December 31, 2005, PVR reported (i) a derivative liability of approximately $0.7 million and (ii) an unrealized loss on derivatives of $0.7 million related to the basis swap.

Interest Rate Swaps

In connection with the issuance of its senior unsecured notes (see Note 14) in March 2003, PVR entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of those notes (the "Senior Notes Swap"). The Senior Notes Swap agreement was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by PVR to the counterparty in July 2005. Upon settlement of the PVR Senior Notes Swap agreement, the $0.8 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the PVR Notes (as defined in Note 15) using the effective interest rate method.

In September 2005, PVR entered into interest rate swap agreements to establish fixed rates on $60 million of the LIBOR-based portion of the outstanding balance on PVR's revolving credit facility (see Note 15) until March 2010 (the

"Revolver Swaps"). PVR pays a weighted average fixed rate of 4.22 percent on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swap agreements were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings as interest expense. At December 31, 2005, PVR reported (i) a derivative asset of approximately $1.2 million and (ii) a gain in accumulated other comprehensive income of $0.8 million, net of related income tax expense of $0.4 million related to the interest rate swap. In connection with periodic settlements, PVR recognized $0.1 million in net hedging losses in interest expense for the year ended December 31, 2005. Based upon future interest rate curves at December 31, 2005, PVR expects to realize $0.3 million of hedging gains within the next 12 months. The amounts that PVR ultimately realizes will vary due to changes in the fair value of open derivative agreements prior to settlement.

12. Accrued Liabilities

Accrued liabilities are summarized as follows (in thousands):

	December 31,	
	2005	2004
Drilling costs	$ 7,720	$ 7,516
Royalties	7,785	6,618
Production and franchise taxes	9,188	4,422
Compensation	5,418	3,111
Deferred income	5,073	1,207
Pipeline imbalance – PVR Midstream	2,504	—
Interest	1,960	1,600
Other	3,601	1,879
Total	$ 43,249	$ 26,353

13. Asset Retirement Obligations

The table below reconciles the beginning and ending aggregate carrying amount of our asset retirement obligations, which are included in other liabilities, or accrued liabilities for the current portion, on the consolidated balance sheets (in thousands):

	Year ended December 31,	
	2005	2004
Balance at beginning of period	$ 3,635	$ 3,389
Liabilities incurred	389	319
Adoption of FIN 47	635	—
Liabilities settled	(280)	(274)
Accretion expense	297	322
	4,676	3,756
Current portion	—	(121)
Balance at end of period	$ 4,676	$ 3,635

14. Other Liabilities

Other liabilities are summarized in the following table (in thousands):

	December 31, 2005	December 31, 2004
Deferred income – PVR Coal	$ 10,194	$ 8,726
Asset retirement obligation	4,676	3,635
Pension	2,093	2,205
Post-retirement health care	2,064	2,075
Environmental liabilities	2,293	1,306
Other	626	148
Total	$ 21,946	$ 18,095

15. Long-Term Debt

Long-term debt as of December 31, 2005 and 2004, consisted of the following (in thousands):

	December 31, 2005	December 31, 2004
Penn Virginia revolving credit facility, variable rate of 5.4 percent at December 31, 2005	$ 79,000	$ 76,000
PVR revolving credit facility, variable rate of 5.7 percent at December 31, 2005	172,000	30,000
PVR senior unsecured notes (1)	82,954	87,726
	333,954	193,726
Less: Current maturities	(8,108)	(4,800)
Total long-term debt	$ 325,846	$ 188,926

(1) Includes negative fair value adjustments of $0.7 million and $0.8 million as of December 31, 2005 and 2004, related to the Senior Notes Swap designated as a fair value hedge. The Senior Notes Swap agreement was settled in June 2005 (see Note 10).

Penn Virginia Revolving Credit Facility

In December 2003, we entered into a revolving credit facility (the "Revolver") with a syndicate of financial institutions led by JP Morgan Chase Bank N.A. The Revolver is secured by a portion of our proved oil and gas reserves. In December 2005, we amended and restated the Revolver to increase the commitment from $150 million to $200 million, increase the borrowing base from $200 million to $300 million, extend the maturity date from December 2007 to December 2010 and attain a more favorable interest rate. We paid loan issue costs of $0.5 million related to the amendment, which were capitalized in other assets and will be amortized over the remaining term of the Revolver.

The Revolver is governed by a borrowing base calculation and is redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.00 to 1.75 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 up to 0.50 percent. The weighted average interest rate on borrowings incurred during the year ended December 31, 2005, was approximately 4.99 percent. In 2005, we incurred commitment fees of $0.3 million on the unused portion of the Revolver. We capitalized $3.5 million, $2.0 million and $2.0 million of interest cost incurred in 2005, 2004 and 2003. The Revolver allows for the issuance of up to $20 million of letters of credit, of which $0.3 million were issued as of December 31, 2005. The financial covenants under the Revolver require us to maintain levels of debt-to-earnings and impose dividend limitation restrictions. As of December 31, 2005, we were in compliance with all of our covenants under the Revolver.

PVR Revolving Credit Facility

Concurrent with the closing of the Cantera Acquisition in March 2005, Penn Virginia Operating Co., LLC, the parent of PVR Midstream LLC and a subsidiary of the Partnership, entered into a new unsecured $260 million, five-year credit agreement with a syndicate of financial institutions led by PNC Bank, National Association ("PNC"). The new agreement consisted of a $150 million revolving credit facility (the "PVR Revolver") that matures in March 2010 and a $110 million term loan. As of December 31, 2005, PVR had $172.0 million of outstanding borrowings under the PVR Revolver. A portion of the PVR Revolver and the term loan were used to fund the Cantera Acquisition and to repay borrowings under PVR's previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million of PVR's common units in March 2005 and a $2.6 million contribution from its general partner (our subsidiary) were used to repay the $110 million term loan and a portion of the amount outstanding under the PVR Revolver. In the fourth quarter of 2004, PVR paid loan issue costs of approximately $1.2 million related to the term loan, which were recorded as interest expense in 2004. The term loan cannot be re-borrowed. The PVR Revolver is available for general Partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR had outstanding letters of credit of $1.6 million as of December 31, 2005. In 2005, PVR incurred commitment fees of $0.4 million on the unused portion of the PVR Revolver.

In July 2005, PVR amended its credit agreement to increase the size of the commitment under the PVR Revolver from $150 million to $300 million and to increase its one-time option (upon receipt by the credit facility's administrative agent of commitments from one or more lenders) to expand the facility from $100 million to $150 million. The amendment also updated certain debt covenant definitions. The interest rate under the credit agreement remained unchanged and will fluctuate based on the Partnership's ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if PVR selects the LIBOR-based borrowing option under the credit agreement or at a rate derived from LIBOR plus an applicable margin ranging from 1.00 percent to 2.00 percent if PVR selects the LIBOR-based borrowing option. The other terms of the credit agreement remained unchanged. The financial covenants under the PVR Revolver require PVR to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR's borrowing capacity under the PVR Revolver to approximately $106.5 million as of December 31, 2005. As of December 31, 2005, the Partnership was in compliance with all of its covenants under the PVR Revolver.

In September 2005, PVR entered into two Revolver Swap agreements to establish a fixed interest rate on $60 million of the LIBOR-based portion of the outstanding balance of the PVR Revolver, which effectively fixed the interest rate at 4.22 percent plus the applicable margin, which was 1.25 percent as of December 31, 2005 (see Note 11).

Prior to the Cantera Acquisition, the Partnership had a $100 million unsecured revolving credit facility that was set to expire in October 2006. The revolving credit facility was with a syndicate of financial institutions led by PNC as its agent. The revolving credit facility was available for general Partnership purposes, including working capital, capital expenditures and acquisitions, and included a $5 million sublimit that was available for working capital needs and distributions and a $5 million sublimit for the issuance of letters of credit.

At the Partnership's option, indebtedness under the revolving credit facility bore interest at either (i) the Eurodollar rate plus an applicable margin which ranged from 1.25 percent to 2.25 percent based on the ratio of consolidated indebtedness to consolidated EBITDA (as defined by the credit agreement) for the four most recently completed fiscal quarters, or (ii) the higher of the federal funds rate plus 0.50 percent or the prime rate as announced by PNC. The Partnership paid commitment fees on the unused portion of the revolving credit facility.

PVR Senior Unsecured Notes

In March 2003, the Partnership closed a private placement of $90 million of senior unsecured notes (the "PVR Notes"). The PVR Notes bore interest at a fixed rate of 5.77 percent and mature over a ten-year period ending in March 2013, with semi-annual principal and interest payments. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. The PVR Notes have an equal priority of payment as all other unsecured indebtedness of PVR, including the PVR Revolver. As of December 31, 2005, the Partnership was in compliance with all of the covenants.

In conjunction with the closing of the Cantera Acquisition, PVR amended the PVR Notes to allow PVR to enter the natural gas midstream business and to increase certain covenant coverage ratios, including the debt to EBITDA test. In exchange for this amendment, PVR agreed to a 0.25 percent increase in the fixed interest rate on the PVR Notes, from 5.77 percent to 6.02 percent. The amendment to the PVR Notes also requires that the Partnership obtain an annual confirmation of its credit rating, with a 1.00 percent increase in the interest rate payable on the PVR Notes in the event the Partnership's credit rating falls below investment grade. On March 15, 2005, PVR's investment grade credit rating was confirmed by Dominion Bond Rating Services.

Upon settlement of the Senior Notes Swap agreement (see Note 11), the $0.7 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the PVR Notes using the interest rate method.

Line of Credit

We have a $5 million line of credit with a financial institution effective through June 2006, renewable annually. We have an option to elect a fixed rate LIBOR loan, floating rate LIBOR loan or base rate (as determined by the financial institution) loan. At December 31, 2005 and 2004, we had no outstanding borrowings against the line of credit.

Debt Maturities

Aggregate maturities of the principal amounts of long-term debt for the next five years and thereafter are as follows (in thousands):

2006	$ 8,300
2007	11,000
2008	12,700
2009	14,100
2010	264,400
Thereafter	24,200
	$ 334,700
Terminated interest rate swap	(746)
Total debt, including current maturities	$ 333,954

16. Income Taxes

The provision for income taxes from continuing operations is comprised of the following (in thousands):

	Year ended December 31,		
	2005	2004	2003
Current income taxes			
Federal	$ 21,708	$ 2,619	$ 2,067
State	1,867	3	1,007
Total current	23,575	2,622	3,074
Deferred income taxes			
Federal	12,007	15,247	12,090
State	5,087	3,978	3,202
Total deferred	17,094	19,225	15,292
Total income tax expense	$ 40,669	$ 21,847	$ 18,366

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 (in thousands):

	Year ended December 31,					
	2005		2004		2003	
Computed at federal statutory tax rate	$ 35,966	35.0%	$ 19,320	35.0%	$ 15,933	35.0 %
State income taxes, net of federal income tax benefit	4,341	4.2%	2,486	4.5%	2,611	5.7 %
Other, net	362	0.4%	41	0.1%	(178)	(0.4)%
Total income tax expense	$ 40,669	39.6%	$ 21,847	39.6%	$ 18,366	40.3 %

The principal components of our net deferred income tax liability are as follows (in thousands):

	December 31, 2005	December 31, 2004
Deferred tax liabilities:		
Oil and gas properties	$ 123,757	$ 97,267
Other	7,638	8,890
Total deferred tax liabilities	131,395	106,157
Deferred tax assets:		
Fair value of derivative instrument	8,023	163
Deferred income—coal properties	5,939	3,112
Pension and post-retirement benefits	1,734	1,603
Net operating loss carryforwards	—	1,810
Other	4,513	1,557
Total deferred tax assets	20,209	8,245
Net deferred tax liability	$ 111,186	$ 97,912

As of December 31, 2005, we estimate that all our net operating loss carryforwards (“NOLs”) for state tax purposes were utilized in 2005.

17. Employee Benefit Plans

401(k) Plan

We sponsor a defined contribution pension plan (the “401(k) Plan”) that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 50 percent of their base salaries. After the employee meets certain service requirements, we match each employee’s contributions up to six percent of the employee’s base salary. Our matching contributions to the 401(k) Plan were approximately $0.6 million, $0.4 million and $0.3 million for the years ended December 31, 2005, 2004 and 2003. Beginning in 2005, we had the option to make additional contributions at our discretion. We made no discretionary contributions in 2005.

Pension Plans and Other Post-retirement Benefits

We provide post-separation (“pension”) payments to certain eligible employees. Benefits are typically based on the employee’s average annual compensation and service.

We also offer post-retirement healthcare benefits to employees hired prior to January 1, 1991, who retire from active service. The benefits include medical and prescription drug coverage for the retirees and dependents and life insurance for the retirees. The medical coverage is noncontributory for retirees who retired on or before December 31, 1990, and may be contributory for retirees who retired on or after January 1, 1991.

We use a December 31 measurement date for these plans.

In July 2004, we adopted FASB Staff Position (“FSP”) SFAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.* The FSP requires employers that qualify for a prescription-drug subsidy under Medicare legislation enacted in December 2003 to recognize the reduction in costs as employees provide services in future years. FSP SFAS 106-2 did not have a significant impact on our financial statements because we do not qualify for the subsidy.

A reconciliation of the changes in the benefit obligations and fair value of assets for the years ended December 31, 2005 and 2004, and a statement of the funded status at December 31, 2005 and 2004, is as follows (in thousands):

	Pension		Post-retirement Healthcare	
	2005	2004	2005	2004
Reconciliation of benefit obligation:				
Obligation—beginning of year	$ 2,348	$ 2,382	$ 4,404	$ 4,490
Service cost	—	—	29	28
Interest cost	129	141	241	261
Benefits paid	(241)	(265)	(461)	(478)
Actuarial loss	6	90	358	103
Obligation—end of year	2,242	2,348	4,571	4,404
Reconciliation of fair value of plan assets:				
Fair value—beginning of year	—	—	—	—
Employer contributions	241	265	438	455
Participant contributions	—	—	23	23
Benefit payments	(241)	(265)	(461)	(478)
Fair value—end of year	—	—	—	—
Funded status:				
Funded status—end of year	(2,242)	(2,348)	(4,571)	(4,404)
Unrecognized transition obligation	6	10	—	—
Unrecognized prior service cost	18	24	847	935
Unrecognized gain	617	642	1,506	1,237
Net amount recognized	$ (1,601)	$ (1,672)	$ (2,218)	$ (2,232)

Because the benefit obligation exceeds the fair value of plan assets, we have recognized a liability in the statements of financial position. The following table provides the components of the benefit obligation recognized in the statements of financial position at December 31, 2005 and 2004 (in thousands):

	Pension		Post-retirement Healthcare	
	2005	2004	2005	2004
Accrued benefit liability	$ (2,242)	$ (2,348)	$ (2,218)	$ (2,232)
Other long-term assets	24	34	—	—
Accumulated other comprehensive income	617	642	—	—
Obligation—end of year	$ (1,601)	$ (1,672)	$ (2,218)	$ (2,232)

The following table provides the components of net periodic benefit cost for the plans for the years ended December 31, 2005 and 2004 (in thousands):

	Pension		Post-retirement Healthcare	
	2005	2004	2005	2004
Service cost	$ —	$ —	$ 29	$ 28
Interest cost	129	141	241	261
Amortization of prior service cost	6	6	88	88
Amortization of transitional obligation	3	3	—	—
Recognized actuarial loss	31	25	66	52
Net periodic benefit cost	$ 169	$ 175	$ 424	$ 429

We used an assumed discount rate of 5.75 percent in 2005 and 2004 for the measurement of our pension and post-retirement healthcare benefit obligations. We base the discount rate on the published Moody's Aa corporate bond yield as of the measurement date. We choose to use the Moody's Aa corporate bond yield because it is a widely available rate and its portfolio approximates the characteristics of our plans.

For measurement purposes, a 10.0 percent annual rate increase in the per capita cost of covered health care benefits was assumed for 2005. The rate is assumed to decrease gradually to five percent for 2013 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 2005 (in thousands):

	One Percent Increase	One Percent Decrease
Effect on total of service and interest cost components	$ 12	$ (12)
Effect on post-retirement benefit obligation	208	(199)

We expect to contribute $0.2 million to the pension plan and $0.4 million to the post-retirement healthcare plan in 2006.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

	Pension	Post-retirement Healthcare
2006	$ 213	$ 438
2007	222	439
2008	218	442
2009	214	438
2010	203	436
2011-2015	800	1,961

18. 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 the last three years (in thousands, except per share data).

	2005	2004	2003
Income from operations before cumulative effect of change in accounting principle	$ 62,088	$ 33,355	$ 27,159
Cumulative effect of change in accounting principle	—	—	1,363
Net income	$ 62,088	$ 33,355	$ 28,522
Weighted average shares, basic	18,546	18,306	17,976
Effect of dilutive securities:			
Stock options	186	161	136
Weighted average shares, diluted	18,732	18,467	18,112
Income from operations before cumulative effect of change in accounting principle per share, basic	$ 3.35	$ 1.82	$ 1.51
Cumulative effect of change in accounting principle per share, basic	—	—	0.08
Net income per share, basic	$ 3.35	$ 1.82	$ 1.59
Income from operations before cumulative effect of change in accounting principle per share, diluted	$ 3.31	$ 1.81	$ 1.50
Cumulative effect of change in accounting principle per share, diluted	—	—	0.08
Net income per share, diluted	$ 3.31	$ 1.81	$ 1.58

Options with an exercise price exceeding the average price of the underlying securities are not considered to be dilutive and are not included in calculation of the denominator for diluted earnings per share for the years ended December 31, 2005 and 2003. All options outstanding at December 31, 2004, had exercise prices exceeding the average price of the underlying securities.

19. Stock Compensation and Stock Ownership Plans

Stock Compensation Plans

We have several stock compensation plans (collectively, the "Stock Compensation Plans") that allow incentive and nonqualified stock options and restricted stock to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. At December 31, 2005, there were approximately 215,000 and 420,000 shares available for issuance to directors and employees pursuant to the Stock Compensation Plans. In 2005, we recognized $0.7 million of compensation expense related to the Stock Compensation Plans. Compensation expense related to the Stock Compensation Plans was not significant in 2004 and 2003.

Stock Options. The exercise price of all options granted under the Stock Compensation Plans is at the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to 10 years following the grant. Options vest upon terms established by the compensation and benefits committee. In addition, all options will vest upon a change of control of the Company. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be automatically forfeited, (ii) by reason of death, disability or retirement, the grantee's options will automatically vest and (iii) for any other reason, the grantee's unvested options will be automatically forfeited. In the case of directors, if a grantee's membership on our Board of Directors terminates for any reason, the grantee's unvested options will be automatically forfeited.

Options granted on or before January 2, 2004, under the Stock Compensation Plans vested on the first anniversary of the date of grant. Options granted after January 2, 2004, vest ratably over a three-year period so that one-third is exercisable after one year, another third is exercisable after two years and the remaining third is exercisable after three years.

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

	2005		2004		2003	
	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	635,900	$ 21.10	801,900	$ 16.46	807,700	$ 14.70
Granted	117,200	$ 49.18	210,000	$ 28.52	206,000	$ 18.71
Exercised	(119,254)	$ 18.37	(364,400)	$ 14.43	(209,800)	$ 11.85
Cancelled / forfeited	(12,215)	$ 33.08	(11,600)	$ 28.09	(2,000)	$ 18.30
Outstanding at end of year	621,631	$ 26.68	635,900	$ 21.10	801,900	$ 16.46
Exercisable at end of year	388,694	$ 19.50	436,300	$ 17.71	597,900	$ 15.69
Weighted average of fair value of options granted during the year		$ 12.28		$ 6.20		$ 5.26

The fair value of the options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions for each grant year:

	2005	2004	2003
Dividend yield	0.81% to 1.10%	1.56% to 1.60%	1.98% to 2.59%
Expected volatility	26.4%	27.7%	27.9%
Risk-free interest rate	3.88% to 4.04%	2.47%	3.70%
Expected life	4 years	4 years	8 years

The following table summarizes certain information regarding stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 12/31/05	Weighted Avg. Remaining Contractual Life	Weighted Avg. Exercise Price/share	Number Exercisable at 12/31/05	Weighted Avg. Exercise Price/share
$13.53 to $19.99	320,950	5.8 years	$ 17.75	320,950	$ 17.75
$20.00 to $39.99	186,031	7.9 years	$ 28.22	67,744	$ 27.79
$40.00 to $55.25	114,650	9.4 years	$ 49.18	—	$ —

Restricted Common Stock. Restricted stock vests upon terms established by the compensation and benefits committee. In addition, all restricted stock will vest upon a change of control of the Company. If a grantee's employment terminates for any reason other than death, disability or retirement, the grantee's restricted stock will be automatically forfeited. If a grantee's employment terminates by reason of death, disability or retirement, the grantee's restricted stock will automatically vest unless otherwise determined by the compensation and benefits committee. Except as specified by the compensation and benefits committee, a grantee shall be entitled to receive any dividends declared on our common stock.

We granted 27,576 shares of restricted common stock at a weighted average grant-date fair value of $58.58 per share to officers and employees in 2005. The restricted stock granted in 2005 vests over a three-year period, with either one-third vesting in each year or 25 percent vesting after the first year, 25 percent vesting after the second year and 50 percent vesting after the third year. We recognize compensation expense on a straight-line basis over the vesting period. No restricted stock was granted prior to January 1, 2005.

Deferred Common Stock Units. A portion of compensation to non-employee members of our Board of Directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, which vests immediately upon issuance and is available to the holder upon termination or retirement from the Board of Directors. Deferred common stock units awarded to directors receive all cash or other dividends we pay on shares of common stock.

We granted 12,824 deferred common stock units to our directors in 2005 at a weighted average grant-date fair value of $45.23 per unit. In accordance with EITF Issue No. 97-14, *Accounting for Deferred Compensation Arrangements Where Amounts Earned Are Held in a Rabbi Trust and Invested,* we recorded a $0.6 million deferred compensation obligation in shareholders' equity and a corresponding amount for treasury stock. No deferred common stock units were granted prior to January 1, 2005.

Employees' Stock Ownership Plan

In July 2004, the Employees' Stock Ownership Plan ("ESOP") was merged with and into the 401(k) Plan.

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 common share outstanding has one right, and each right entitles the holder to purchase from us 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 10 percent or more if such person or group has been deemed to be 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 (i) common stock of the Company, (ii) a combination of cash, other property, or common stock or other securities of the Company, or (iii) 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.

PVR Long-Term Incentive Plan

The general partner of the Partnership has a long-term incentive plan that permits the grant of awards covering an aggregate of 300,000 common units to employees and directors of the general partner and employees of the general partner's affiliates who perform services for the Partnership. Awards under the long-term incentive plan can be in the form of common units, restricted units, unit options, phantom units and deferred common units. The long-term incentive plan is administered by the compensation and benefits committee of the board of directors of the general partner. Compensation expense related to the long term incentive plan totaled $1.4 million, $0.4 million and $0.2 million for the years ended December 31, 2005, 2004 and 2003.

Common Units. The general partner of the Partnership granted 438 common units at a weighted average grant-date fair value of $50.71 per unit to non-employee directors in 2005. The general partner granted 4,961 common units at a weighted average grant-date fair value of $34.83 per unit to non-employee directors in 2004. The general partner granted 3,000 common units at a weighted average grant-date fair value of $20.95 per unit to non-employee directors in 2003.

Restricted Units. Restricted units vest upon terms established by the compensation and benefits committee, but in no case earlier than the conversion to common units of PVR's outstanding subordinated units. In addition, all restricted units will vest upon a change of control of the general partner or us. If a grantee's employment with, or membership on the board of directors of, the general partner terminates for any reason, the grantee's unvested restricted units will be automatically forfeited unless, and to the extent, that the compensation and benefits committee provides otherwise. Distributions payable with respect to restricted units may, in the compensation and benefits committee's discretion, be paid directly to the grantee or held by the general partner and made subject to a risk of forfeiture during the applicable restriction period.

The general partner of the Partnership granted 25,488 restricted units at a weighted average grant-date fair value of $50.76 per unit to officers and employees of the general partner in 2005. The general partner granted 16,400 restricted units at a weighted average grant-date fair value of $34.66 per unit to officers and employees of the general partner in 2004. The general partner granted 12,950 restricted units at a weighted average grant-date fair value of $23.97 per unit to directors, officers and employees of the general partner in 2003. The restricted units granted in 2005 vest over a three-year period, with one-third vesting in each year. The restricted units granted in 2004 and 2003 vested on the first anniversary of the date of grant.

Deferred Common Units. A portion of compensation to non-employee directors of the general partner of PVR is paid in deferred common units. Each deferred common unit represents one common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of the general partner. Common units delivered in connection with deferred common 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 PVR or any other person, or any combination of the foregoing. The general partner is entitled to reimbursement by PVR for the cost incurred in acquiring common units. Deferred common units awarded to directors receive all cash or other distributions paid by PVR on account of common units. The general partner of the Partnership granted 8,855 deferred common units at a weighted average grant-date fair value of $50.54 per unit to non-employee directors in 2005. No deferred common units were granted prior to January 1, 2005.

20. Other Comprehensive Income

Comprehensive income represents certain changes in equity during the reporting period, including net income and charges directly to equity which are excluded from net income. For the three years ended December 31, 2005, 2004 and 2003, the components of other comprehensive income were as follows (in thousands):

	Cash Flow Hedges	Minimum Pension Liability	Total
Hedging unrealized loss, net of tax of $8,726	$(16,206)	$ —	$(16,206)
Hedging reclassification adjustment, net of tax of $4,897	9,094	—	9,094
Pension plan adjustment, net of tax of $9	—	16	16
Other comprehensive income for the year ended December 31, 2005	$ (7,112)	$ 16	$ (7,096)
Hedging unrealized loss, net of tax of $1,214	$ (2,254)	$ —	$ (2,254)
Hedging reclassification adjustment, net of tax of $2,060	3,826	—	3,826
Pension plan adjustment, net of tax of $23	—	(42)	(42)
Other comprehensive income for the year ended December 31, 2004	$ 1,572	$ (42)	$ 1,530
Hedging unrealized loss, net of tax of $2,428	$ (4,509)	$ —	$ (4,509)
Hedging reclassification adjustment, net of tax of $2,141	3,976	—	3,976
Pension plan adjustment, net of tax of $30	—	(56)	(56)
Other comprehensive income for the year ended December 31, 2003	$ (533)	$ (56)	$ (589)

21. 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 operating decision maker, or decision-making group, in assessing performance. Our chief operating decision-making group consists of our Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our oil and gas operations, PVR's coal operations and PVR's natural gas midstream operations. Accordingly, our reportable segments are as follows:

- Oil and Gas – crude oil and natural gas exploration, development and production.
- Coal (the "PVR Coal" segment) – the leasing of mineral interests and subsequent collection of royalties, the providing of fee-based coal handling, transportation and processing infrastructure facilities, and the development and harvesting of timber.
- Natural Gas Midstream (the "PVR Midstream" segment) – gas processing, gathering and other related services.

In 2004, we reported two operating segments – 1) oil and gas and 2) coal. As a result of the Cantera Acquisition, we added the natural gas midstream segment. The following segment information for the years ended December 31, 2004 and 2003, has been restated to conform to the current period's presentation. The following is a summary of certain financial information relating to our segments (in thousands):

	Oil and Gas	PVR Coal	PVR Midstream (4)	Corporate and Other	Consolidated
As of and for the Year Ended December 31, 2005					
Revenues	$ 226,819	$ 95,755	$ 350,593	$ 697	$ 673,864
Operating costs and expenses	80,669	16,121	321,509	11,826	430,125
Depreciation, depletion and amortization	45,885	17,890	12,738	424	76,937
Impairment of oil and gas properties	4,785	—	—	—	4,785
Operating income (loss)	$ 95,480	$ 61,744	$ 16,346	$ (11,553)	162,017
Interest expense					(15,318)
Interest income and other					1,332
Unrealized loss on derivatives					(14,885)
Income before minority interest and taxes					$ 133,146
Total assets	$ 576,634	$ 372,322	$ 285,557	$ 17,033	$ 1,251,546
Additions to property and equipment and acquisitions, net of cash acquired (1)	171,301	112,497	206,811	350	490,959
Equity investments	—	26,612	60	—	26,672
As of and for the Year Ended December 31, 2004					
Revenues	$ 151,672	$ 75,630	$ —	$ 1,123	$ 228,425
Operating costs and expenses	57,668	16,479	—	10,334	84,481
Depreciation, depletion and amortization	35,886	18,632	—	434	54,952
Loss on assets held for sale	7,541	—	—	—	7,541
Impairment of oil and gas properties	655	—	—	—	655
Operating income (loss)	$ 49,922	$ 40,519	$ —	$ (9,645)	80,796
Interest expense					(7,672)
Interest income and other					1,101
Income before minority interest and taxes					$ 74,225
Total assets	$ 482,343	$ 284,435	$ —	$ 16,557	$ 783,335
Additions to property and equipment and acquisitions, net of cash acquired (2)	123,977	2,148	—	176	126,301
Equity investments	—	27,881	—	—	27,881
As of and for the Year Ended December 31, 2003					
Revenues	$ 124,822	$ 55,642	$ —	$ 820	$ 181,284
Operating costs and expenses	44,937	12,504	—	11,227	68,668
Depreciation, depletion and amortization	33,164	16,578	—	367	50,109
Impairment of oil and gas properties	406	—	—	—	406
Operating income (loss)	$ 46,315	$ 26,560	$ —	$ (10,774)	62,101
Interest expense					(5,304)
Interest income and other					1,238
Income before minority interest and taxes					$ 58,035
Total assets	$ 405,753	$ 259,892	$ —	$ 18,088	$ 683,733
Additions to property and equipment and acquisitions, net of cash acquired (3)	122,270	10,458	—	621	133,349

(1) Coal segment includes noncash expenditures of $14.4 million related to acquisitions and $1.2 million related to the timing of payment of invoices.
(2) Coal segment includes noncash expenditures of $1.1 million.
(3) Coal segment includes noncash expenditures of $5.2 million.
(4) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.

Operating income does not include certain other income items, interest expense, minority interest and income taxes.

For the year ended December 31, 2005, two customers of the natural gas midstream segment accounted for approximately $81.9 million and $77.1 million, or 12 percent and 11 percent, of consolidated net revenues. In June 2005, one of our subsidiaries began leasing railcars from a subsidiary of PVR. Railcar rental revenues were $0.4 million in 2005 and are included in the PVR Coal segment. The offsetting railcar rental expense and the elimination of the revenue and expense are included in the corporate and other column of the preceding table.

For the year ended December 31, 2004, two customers of the oil and gas segment accounted for approximately $32.3 million and $28.2 million, or 14 percent and 12 percent, of our consolidated net revenues.

For the year ended December 31, 2003, three customers of the oil and gas segment accounted for approximately $34.8 million, $24.2 million and $21.9 million, or 19 percent, 13 percent and 12 percent, of our consolidated net revenues.

22. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2005, 2004 and 2003, was $5.8 million, $4.2 million and $3.1 million. Minimum rental commitments for the next five years under all non-cancelable operating leases in effect at December 31, 2005, were as follows (in thousands):

For the Year Ending December 31,	
2006	$ 4,412
2007	2,760
2008	1,193
2009	611
2010	590
Total minimum payments	$ 9,566

Rental commitments primarily relate to equipment, car, building and land leases. Also included are the Partnership's rental commitments, which primarily relate to coal reserve-based properties which the Partnership subleases, or intends to sublease, 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 future rental commitments cannot be estimated with certainty; however, based on current knowledge, we believe the Partnership will incur approximately $0.6 million in rental commitments annually until the reserves have been exhausted.

Drilling Commitments

In June 2005, we entered into an agreement to purchase oil and gas well drilling services from a third party for two years. The agreement includes early termination provisions that would require us to pay a penalty if we terminate the agreement prior to the original two-year term. The amount of the penalty is based on the number of days remaining in the two-year term and declines as time passes. As of December 31, 2005, the penalty amount would have been $4.2 million if we had terminated the agreement on that date. Management intends to utilize drilling services under this agreement for the full two-year term and has no plans to terminate the agreement early.

In January 2006, we entered into another agreement to purchase oil and gas drilling services from a different third party for three years. The agreement includes early termination provisions that would require us to pay a penalty if we terminate the agreement prior to the original three-year term. The amount of the penalty is based on the number of days remaining in the three-year term and declines as time passes. Management intends to utilize drilling services under this agreement for the full three-year term and has no plans to terminate the agreement early.

Firm Transportation Commitments

In 2004, we entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 10 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion. Our obligation for firm transportation commitments in effect at December 31, 2005, for the next five years and thereafter is as follows (in thousands):

Year ending December 31,		
2006	$	1,769
2007		1,609
2008		1,081
2009		1,081
2010		1,081
Thereafter		4,233
Total	$	10,854

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 coal lessees and natural gas midstream segment 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 coal properties under lease to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of the Partnership’s coal lessees and natural gas midstream segment will comply with existing regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2005 and 2004, the Partnership’s environmental liabilities included $2.5 million and $1.5 million, which represents our best estimate of the liabilities as of those dates related to the coal and natural gas midstream businesses. The Partnership has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when the reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

23. Quarterly Financial Information (Unaudited)

Summarized Quarterly Financial Data

	2004 Quarters Ended				2005 Quarters Ended (1)			
	(in thousands, except share data)							
	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	$ 55,626	$ 54,569	$ 52,741	$ 65,489	$ 88,210	$ 157,965	$ 186,393	$ 241,296
Operating income	$ 22,354	$ 25,665	$ 17,493	$ 15,284	$ 27,704	$ 26,417	$ 46,808	$ 61,088
Net income	$ 10,142	$ 12,080	$ 6,434	$ 4,699	$ 7,040	$ 7,647	$ 19,990	$ 27,411
Net income per share (2):								
Basic	$ 0.56	$ 0.66	$ 0.35	$ 0.26	$ 0.38	$ 0.41	$ 1.08	$ 1.47
Diluted	$ 0.55	$ 0.65	$ 0.35	$ 0.25	$ 0.38	$ 0.41	$ 1.07	$ 1.46
Weighted average shares outstanding:								
Basic	18,168	18,293	18,357	18,414	18,490	18,517	18,560	18,613
Diluted	18,352	18,479	18,574	18,610	18,694	18,719	18,760	18,818

(1) Includes the results of operations from the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) 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.

24. Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following supplemental 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

	December 31,		
	2005	2004	2003
	(in thousands)		
Proved properties	$ 126,286	$ 120,742	$ 123,302
Unproved properties	66,727	61,013	60,042
Wells, equipment and facilities	502,877	392,230	316,257
Support equipment	4,088	3,461	3,689
	699,978	577,446	503,290
Accumulated depreciation and depletion	(191,860)	(148,212)	(116,998)
Net capitalized costs (1)	$ 508,118	$ 429,234	$ 386,292

(1) Net capitalized costs of $16.4 million at December 31, 2005, and $13.7 million at December 31, 2004, relating to a transmission pipeline and compression in the Appalachian Basin placed into service during 2005 and 2004 were excluded from net capitalized costs.

In accordance with SFAS No. 143, as of January 1, 2003, the cost basis of oil and gas wells were increased by approximately $1.0 million. During 2005, 2004 and 2003, an additional $0.4 million, $0.3 million and $0.4 million was added to the cost basis of oil and gas wells for wells drilled.

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Proved property acquisition costs	$ —	$ —	$ 35,131
Unproved property acquisition costs	26,360	13,046	9,021
Exploration costs	30,335	26,429	21,401
Development costs and other (1)	109,066	82,048	67,783
Total costs incurred	$ 165,761	$ 121,523	$ 133,336

(1) Development costs of $3.8 million in 2005 and $13.7 million in 2004 relating to a transmission pipeline and compression in the Appalachian Basin placed into service during 2005 and 2004 were excluded from 2005 and 2004 costs incurred.

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.

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Revenues	$ 226,219	$ 151,786	$ 123,431
Production expenses	30,940	23,728	21,928
Exploration expenses	40,917	26,058	15,503
Depreciation and depletion expense(1)	44,865	35,772	33,164
Impairment of oil and gas properties	4,785	655	406
	104,712	65,573	52,430
Income tax expense	41,466	25,967	21,338
Results of operations	$ 63,246	$ 39,606	$ 31,092

(1) Depreciation expense of $0.9 million in 2005 and $0.1 million in 2004 relating to a transmission pipeline and compression in the Appalachian Basin placed into service during 2005 and 2004 were excluded from 2005 and 2004 depreciation and depletion expense.

In accordance with SFAS No. 143, the combined depletion and accretion expense related to asset retirement obligations that were recognized during 2005, 2004 and 2003 in depreciation, depletion and amortization expense was approximately $0.2 million, $0.5 million and $0.2 million.

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, 2005, 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 wells with 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)	Total Equivalents (MMcfe)
December 31, 2002	5,361	241,255	273,421
Revisions of previous estimates	101	(5,302)	(4,696)
Extensions, discoveries and other additions	232	53,088	54,480
Production	(625)	(20,094)	(23,844)
Purchase of reserves	1,567	14,354	23,756
Sale of reserves in place	(2)	(232)	(244)
December 31, 2003	6,634	283,069	322,873
Revisions of previous estimates	(418)	(13,669)	(16,177)
Extensions, discoveries and other additions	532	70,010	73,202
Production	(396)	(22,079)	(24,455)
Purchase of reserves	—	—	—
Sale of reserves in place	(9)	(1,279)	(1,333)
December 31, 2004	6,343	316,052	354,110
Revisions of previous estimates	(35)	(13,859)	(14,071)
Extensions, discoveries and other additions	554	87,860	91,184
Production	(306)	(25,676)	(27,515)
Purchase of reserves	—	—	—
Sale of reserves in place	(3,659)	(5,196)	(27,148)
December 31, 2005	2,897	359,181	376,560
Proved Developed Reserves:			
December 31, 2003	3,346	230,958	251,034
December 31, 2004	2,895	243,480	260,850
December 31, 2005	2,017	266,970	279,070

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,		
	2005	2004	2003
		(in thousands)	
Future cash inflows	$ 3,902,546	$ 2,310,163	$ 1,965,224
Future production costs	(637,907)	(460,729)	(392,193)
Future development costs	(192,938)	(123,928)	(70,105)
Future net cash flows before income tax	3,071,701	1,725,506	1,502,926
Future income tax expense	(834,774)	(455,328)	(407,411)
Future net cash flows	2,236,927	1,270,178	1,095,515
10% annual discount for estimated timing of cash flows	(1,200,481)	(680,525)	(583,823)
Standardized measure of discounted future net cash flows	$ 1,036,446	$ 589,653	$ 511,692

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Sales of oil and gas, net of production costs	$ (236,809)	$ (128,058)	$ (101,503)
Net changes in prices and production costs	516,662	46,269	92,640
Extensions, discoveries and other additions	327,287	177,914	142,921
Development costs incurred during the period	25,725	14,705	15,503
Revisions of previous quantity estimates	(54,479)	(38,771)	(10,380)
Purchase of minerals-in-place	—	—	68,071
Sale of minerals-in-place	(59,864)	(3,722)	(36)
Accretion of discount	79,459	69,585	48,114
Net change in income taxes	(170,261)	(20,779)	(57,942)
Other changes	19,073	(39,182)	(40,619)
Net increase (decrease)	446,793	77,961	156,769
Beginning of year	589,653	511,692	354,923
End of year	$ 1,036,446	$ 589,653	$ 511,692

As required by SFAS No. 69, 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" earlier in this Note and the statements of cash flows in the consolidated financial statements.

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

None.

Item 9A ***Controls and Procedures***

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2005. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2005, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2005. This evaluation was completed based on the framework established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In conducting management's evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2005, we have excluded our natural gas midstream business, which was acquired on March 3, 2005 and which now operates as PVR Midstream LLC, as permitted by the SEC. PVR Midstream LLC's total assets were $241.9 million, or approximately 19 percent of our total assets as of December 31, 2005, and PVR Midstream LLC's total revenues were $350.6 million, or approximately 52 percent of our total revenues, for the year ended December 31, 2005.

Our management has concluded that, as of December 31, 2005, our internal control over financial reporting was effective. KPMG LLP, an independent registered public accounting firm, has issued an attestation report on our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, which is included in Item 8 of this Form 10-K.

(c) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B ***Other Information***

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2005 which we did not disclose.

PART III

Item 10 ***Directors and Executive Officers of the Registrant***

Except for information concerning our executive officers included Item 1 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 11 ***Executive Compensation***

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 Annual Report on Form 10-K.

Item 12 ***Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters***

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 Annual Report on Form 10-K.

Item 13 ***Certain Relationships and Related Transactions***

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 Annual Report on Form 10-K.

Item 14 ***Principal Accounting Fees and Services***

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 Annual Report on Form 10-K.

PART IV

Item 15 ***Exhibits, Financial Statement Schedules***

The following documents are filed as exhibits to this Annual Report on Form 10-K.

(1) Financial Statements—The financial statements filed herewith are listed in the Index to Financial Statements on page 51 of this Annual Report on Form 10-K.

(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) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).

(3.4) Amended and Restated Bylaws of Registrant (incorporated by reference to Exhibit 3(ii) to Registrant's Report on Form 8-K filed on December 2, 2004).

(4.1) Rights Agreement dated as of February 11, 1998 between Penn Virginia Corporation and American Stock Transfer & Trust Company (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 as of March 27, 2002 by and between Penn Virginia Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.1 to Registrant's Report on Form 8-K filed on March 28, 2002).

(10.1) Amended and Restated Credit Agreement dated as of December 4, 2003 among Penn Virginia Corporation, the lenders party thereto, Bank One, NA, as Administrative Agent, Wachovia Bank, National Association, as Syndication Agent, Royal Bank of Canada, BNP Paribas and Fleet National Bank, as Documentation Agents, and Banc One Capital Markets, Inc. and Wachovia Capital Markets, LLC, as Co-Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

(10.2) First Amendment to Amended and Restated Credit Agreement dated as of December 29, 2004 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A.

(10.3) Second Amendment to Amended and Restated Credit Agreement dated as of December 15, 2005 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A.

(10.4) 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).

(10.5) Amendment No. 1 to Omnibus Agreement dated December 19, 2002 among the 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 10.9 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

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

(10.7) Penn Virginia Corporation Supplemental Employees Retirement Plan, as amended.*

(10.8) Penn Virginia Corporation Non-Employee Directors Deferred Compensation Plan.*

(10.9) 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).*

(10.10) Penn Virginia Corporation 1995 Fourth Amended and Restated Directors' Stock Compensation Plan (incorporated by reference to Exhibit 10.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.11) Penn Virginia Corporation Second Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 27, 2006).

(10.12) Form of restricted stock award agreement (incorporated by reference to Exhibit 10.13 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.13) Form of deferred common stock award agreement (incorporated by reference to Exhibit 10.14 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.14) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and A. James Dearlove (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 2, 2006).*

(10.15) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and Frank A. Pici (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 2, 2006).

(10.16) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on March 2, 2006).*

(10.17) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 10-Q filed on March 2, 2006).*

(10.18) Executive Change of Control Severance Agreement dated March 9, 2006 between Penn Virginia Resource GP, LLC and Keith D. Horton (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 14, 2006).*

(10.19) Executive Change of Control Severance Agreement dated March 9, 2006 between Penn Virginia Resource GP, LLC and Ronald K. Page (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 14, 2006).*

(12.1) Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.

(21.1) Subsidiaries of Registrant (incorporated by reference to Exhibit 21 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).

(23.1) Consent of KPMG LLP.

(23.2) Consent of Wright & Company, Inc.

(31.1) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2) Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

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

* Management contract or compensatory plan or arrangement.

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 16, 2006	By: /s/ FRANK A. PICI Frank A. Pici Executive Vice President and Chief Financial Officer
March 16, 2006	By: /s/ FORREST W. MCNAIR Forrest W. McNair Vice President and Controller

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

/S/ ROBERT GARRETT **(Robert Garrett)**	Chairman of the Board and Director	March 16, 2006
/S/ JOE N. AVERETT, JR. **(Joe N. Averett, Jr.)**	Director	March 16, 2006
/S/ EDWARD B. CLOUES, II **(Edward B. Cloues, II)**	Director	March 16, 2006
/S/ A. JAMES DEARLOVE **(A. James Dearlove)**	Director and President and Chief Executive Officer	March 16, 2006
/S/ KEITH D. HORTON **(Keith D. Horton)**	Director and Executive Vice President	March 16, 2006
/S/ STEVEN W. KRABLIN **(Steven W. Krablin)**	Director	March 16, 2006
/S/ MERRILL A. MILLER, JR. **(Merrill A. Miller, Jr.)**	Director	March 16, 2006
/S/ MARSHA R. PERELMAN **(Marsha R. Perelman)**	Director	March 16, 2006
/S/ PHILIPPE VAN MARCKE DE LUMMEN **(Philippe van Marcke de Lummen)**	Director	March 16, 2006
/S/ GARY K. WRIGHT **(Gary K. Wright)**	Director	March 16, 2006