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: 1-16735

Penn Virginia Resource Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**23-3087517**
(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:

Title of each class	Name of exchange on which registered
Common Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

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 the 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 Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act)
Yes ☐ No ☒

The aggregate market value of common units held by non-affiliates of the registrant was $609,159,278 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 units as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors, all executive officers, the registrant's general partner and the general partner's affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 8, 2006, 16,997,325 common units and 3,824,940 subordinated units of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
None

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

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Part I

Item 1 *Business*

General

Penn Virginia Resource Partners, L.P. (the "Partnership," "we," "us" or "our") is a Delaware limited partnership formed by Penn Virginia Corporation ("Penn Virginia") in 2001 primarily to engage in the business of managing coal properties in the United States. Since the acquisition of a natural gas midstream business in March 2005, we conduct operations in two business segments: coal and natural gas midstream. In 2005, approximately 79 percent of our operating income was attributable to our coal segment, and approximately 21 percent of our operating income was attributable to our natural gas midstream segment.

Coal Segment Overview

In our coal segment, we owned or controlled approximately 689 million tons of coal as of December 31, 2005. We enter into long-term leases with experienced, third-party mine operators providing them the right to mine our coal reserves in exchange for royalty payments. We do not operate any mines. In 2005, our lessees produced 30.2 million tons of coal from our properties and paid us coal royalty revenues of $82.7 million, for an average gross coal royalty per ton of $2.74. Approximately 83 percent of our coal royalty revenues in 2005 and 79 percent of our coal royalty revenues in 2004 were derived from coal mined on our 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 our coal royalty revenues for the respective periods was derived from coal mined on our properties under leases containing fixed royalty rates which escalate annually. Substantially all of our leases require the lessee to pay minimum rental payments in monthly or annual installments. We actively work with our lessees to develop efficient methods to exploit our reserves and to maximize production from our properties. We earn revenues from providing fee-based coal preparation and transportation services to our 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 our joint venture with Massey Energy Company ("Massey"). We also earn revenues from oil and gas royalty interests we own, from coal transportation ("wheelage") rights and from the sale of standing timber on our properties.

As of December 31, 2005, our primary coal reserves and coal infrastructure assets were located on 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.

Our management continues to focus on acquisitions which increase and diversify our sources of cash flow. We 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 us. Our 2005 acquisitions also included oil and natural gas well royalty interests and wheelage rights. For a more detailed discussion of our 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, we 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, we own and operate 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. Our 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 our cash flows into another long-lived asset base. Since acquiring this business, we have focused on integrating the accounting and commercial systems necessary to prudently operate a natural gas midstream business and have expanded our natural gas midstream business by adding 27 miles of new gathering lines which connect 92 new wells to our gathering and processing systems.

For the ten months ended December 31, 2005, our midstream operations generated a gross processing margin of $44.7 million, consisting of midstream revenues minus the cost of gas purchased. Inlet volumes at our gas processing plants and gathering systems were 38.9 billion cubic feet (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 our natural gas midstream customers, BP Canada Energy Marketing Corp. and ConocoPhillips Company, accounted for 18 percent and 17 percent of our consolidated revenues in 2005.

We continually seek new supplies of natural gas to both offset the natural declines in production from the wells currently connected to our systems and to increase throughput volume. New natural gas supplies are obtained for all of our 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 coal segment, the natural gas midstream segment and the Partnership in general are:

- Coal segment
  - Continue to grow coal reserve holdings, including in our Appalachian core area and new areas. For example, our 2005 investment in Illinois Basin coal reserves was made because we view the Illinois Basin as a growth area, both because of its proximity to power plants and because we expect future environmental regulations will require scrubbing of most coals, including lower sulfur coals from other basins. We expect to continue to diversify our coal reserve holdings into this and other domestic basins in the future.
  - Expand our coal services and infrastructure business on our properties. Coal infrastructure projects are typically long-lived, fee-based assets which generally produce steady and predictable cash flows and, therefore, are attractive to master limited partnerships. We own a number of coal preparation and loading facilities. In 2005, we began constructing a new preparation and loading facility on property we acquired in 2005, which is expected to commence operation in 2006. We intend to continue to look for growth opportunities in this area of operations.
  - Expand our joint venture with Massey to provide new coal handling facilities to industrial end users. In addition to the fee-based coal-related infrastructure projects involving end users of coal in several manufacturing applications, the joint venture purchased an interest in a business which manufactures coal quality analyzing equipment used in the coal mining industry, which, in addition to providing future profits and cash flow, is expected to provide other business development opportunities for coal-related infrastructure projects.
- Natural gas midstream segment (PVR Midstream)
  - Expand PVR Midstream organically, by expanding our gathering systems to add new natural gas production to our existing gathering and processing systems, and through acquisitions of new stand-alone midstream assets that are contiguous to or can be assimilated into our systems. In 2005, we added approximately 27 miles of new gathering lines, allowing us to connect over 90 new wells to our systems.
  - Identify and acquire new gathering, processing and related assets. The natural gas midstream sector is well-suited to our master limited partnership structure and includes many potential acquisition opportunities. Our business development personnel are actively seeking new acquisition opportunities in the sector.
  - Explore ways to provide services to Penn Virginia's oil and gas exploration and production business. For example, during 2005, we began marketing Penn Virginia's natural gas production in Texas and Louisiana, replacing a third party marketing company and allowing Penn Virginia to realize higher prices for its oil and natural gas sold in that region. We will continue to look for ways to exploit our natural link to Penn Virginia in mutually beneficial ways.
- Partnership
  - Maintain financial discipline and flexibility. We intend to continue to be fiscally conservative and manage our capital structure for the long term, which means that we will continue to be cautious regarding debt levels and distribution increases. For example, in order to reduce our debt level, we completed a secondary public offering of new common units in 2005 following the closing of the Cantera Acquisition.

Coal Leases

We earn most of our coal royalty revenues under long-term leases that generally require our lessees to make royalty payments to us based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell. The balance of our coal royalty revenues are earned under two long-term leases with affiliates of Peabody Energy Corporation (NYSE: BTU) ("Peabody") that require the lessees to make royalty payments to us based on fixed royalty rates which escalate annually. A typical lease either expires upon exhaustion of the leased reserves, which is the case with the two Peabody leases, or has a five to ten-year base term, with the lessee having an option to extend the lease for at least five years after the expiration of the base term.

Substantially all of our leases require the lessee to pay minimum rental payments in monthly or annual installments, even if no mining activities are ongoing. These minimum rentals are recoupable, usually over a period from one to three years from the time of payment, against the production royalties owed to us once coal production commences.

In addition to the terms described above, substantially all of our leases impose obligations on the lessees to diligently mine the leased coal using modern mining techniques, indemnify us for any damages we incur in connection with the lessee's mining operations, including any damages we may incur due to the lessee's failure to fulfill reclamation or other environmental obligations, conduct mining operations in compliance with all applicable laws, obtain our written consent prior to assigning the lease, and maintain commercially reasonable amounts of general liability and other insurance. Substantially all of the leases grant us the right to review all lessee mining plans and maps, enter the leased premises to examine mine workings and conduct audits of lessees' compliance with lease terms. In the event of a default by a lessee, substantially all of the leases give us the right to terminate the lease and take possession of the leased premises.

Ownership by and Relationship with Penn Virginia Corporation

One of our attributes is our relationship with Penn Virginia, a publicly held energy company based in Radnor, Pennsylvania. Penn Virginia has been engaged in the coal royalty business since 1882 and is also engaged in the exploration, development and production of oil and natural gas. Penn Virginia formed the Partnership in July 2001 to own and operate substantially all of the assets of and assume the liabilities relating to Penn Virginia's coal land management business. We completed our initial public offering (the "IPO") on October 30, 2001. Penn Virginia continues to hold a significant interest in us through its indirect ownership of a 37 percent limited partner interest and the two percent sole general partner interest in us.

Penn Virginia has a history of successfully completing energy acquisitions. We pursue acquisitions independently and have the opportunity to participate jointly with Penn Virginia in reviewing potential acquisitions. These may include acquisitions of properties containing multiple natural resources, such as oil, natural gas, coal and timber, as well as infrastructure related to those resources, such as natural gas gathering systems and coal preparation plants and loading facilities. We would expect to retain all coal reserves and related infrastructure, all timber resources and all natural gas gathering systems acquired in any such joint acquisition and to allocate the remaining purchased assets between the Partnership and Penn Virginia as appropriate after considering each entity's characteristics and strategies. We expect that our ability to participate in potential acquisitions with, and our access to the experienced management team and industry contacts of, Penn Virginia will benefit us.

Our partnership agreement provides that our general partner, which is an indirect wholly owned subsidiary of Penn Virginia, is restricted from engaging in any coal-related business activities other than those incidental to its ownership of interests in us. Under an omnibus agreement we entered into with Penn Virginia and our general partner concurrently with the closing of the IPO, Penn Virginia and its controlled affiliates agreed not to engage in the businesses of (i) owning, mining, processing, marketing or transporting coal, (ii) owning, acquiring or leasing coal reserves or (iii) growing, harvesting or selling timber, unless it first offers us the opportunity to acquire such businesses or assets and the board of directors of our general partner, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. This restriction did not apply to the assets and businesses retained by Penn Virginia at the closing of the IPO. Under the omnibus agreement, Penn Virginia will be able to purchase any business which includes the purchase of coal reserves, timber or infrastructure relating to the production or transportation of coal if the majority value of such business is not derived from owning, mining, processing, marketing or transporting coal or growing, harvesting or selling timber. If Penn Virginia makes any such acquisition, it must offer us the opportunity to purchase the coal reserves, timber or related infrastructure following the acquisition.

Concurrently with the closing of the IPO, Penn Virginia also agreed to indemnify us through October 2006 in an aggregate amount of up to $10 million for certain pre-existing tax and environmental liabilities.

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through an operating company, Penn Virginia Operating Co., LLC (the "Operating Company"). At March 8, 2006, our Partnership structure was as follows:

- Penn Virginia Resource GP, LLC, our general partner and an indirect wholly owned subsidiary of Penn Virginia, owns the two percent general partner interest in us;
- Penn Virginia Resource LP Corp., Kanawha Rail Corp. and Penn Virginia Resource GP, LLC, indirect wholly owned subsidiaries of Penn Virginia, own an aggregate of 3,894,484 common units and 3,824,940 subordinated units, representing an aggregate 37 percent limited partner interest in us;
- we own 100 percent of the membership interests in the Operating Company; and
- the Operating Company owns 100 percent of the membership interests in its subsidiaries, which include Fieldcrest LLC, K Rail LLC, Loadout LLC, PVR Midstream LLC, Suncrest LLC and Wise LLC.

Our general partner and its affiliates are entitled to distributions on our general partner interest and on any common units and subordinated units they hold. Additionally, our general partner is entitled to distributions on its incentive distribution rights. Our general partner has sole responsibility for conducting our business and for managing our operations. Our general partner will not receive any management fee or other compensation in connection with its management of our business, but will be entitled to be reimbursed for all direct and indirect expenses incurred on our behalf. See Note 13 in the Notes to Consolidated Financial Statements.

On February 23, 2006, the board of directors of our general partner declared a two-for-one split of our common and subordinated units. To effect the split, we will distribute one additional common unit and one additional subordinated unit (a total of 16,997,325 common units and 3,824,940 subordinated units) on April 4, 2006, for each common unit and subordinated unit, respectively, held of record at the close of business on March 28, 2006.

Partnership Distributions

Cash Distributions

We paid cash distributions of $2.4825 per common and subordinated unit during the year ended December 31, 2005. In the first quarter of 2006, we 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, we expect to make quarterly distributions of $0.70 ($2.80 annualized) or more per common and subordinated unit.

Incentive Distribution Rights

In accordance with the partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.50 per unit ($2.00 per unit on an annual basis). Our general partner 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 our general partner with or into such entity or the transfer of all or substantially all of our general partner's assets to another entity without the prior approval of our unitholders if the transferee agrees to be bound by the provisions of our partnership agreement. Prior to September 30, 2011, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of the 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 distribution rights are payable as follows:

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have 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, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner in the following manner:

- First, 98 percent to all unitholders, and two percent to our 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 our 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 our 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 our general partner.

Subordination Period

During the subordination period, which we describe below, the 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.

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.

Subordinated Units

The subordinated units are a separate class of limited partner interests in our partnership, and the rights of holders of subordinated units to participate in distributions to limited partners differ from, and are subordinated to, the rights of the holders of common units as set forth above under “Partnership Distributions—Subordination Period.” If we liquidate during the subordination period, in some circumstances, holders of outstanding common units will be entitled to receive more per unit in liquidating distributions than holders of outstanding subordinated units. The per unit difference will be dependent upon the amount of gain or loss recognized by us in liquidating our assets. Following conversion of the subordinated units into common units, all units will be treated the same upon liquidation of our partnership. Holders of subordinated units will sometimes vote as a single class together with the holders of common units and sometimes vote as a class separate from the holders of common units and, as in the case of holders of common units, will have very limited voting rights. During the subordination period, common units and subordinated units each vote separately as a class on the following matters:

- a sale or exchange of all or substantially all of our assets;
- the election of a successor general partner in connection with the removal of our general partner;
- a dissolution or reconstitution of our partnership;
- a merger of our partnership;
- the issuance of limited partner interests in some circumstances; and
- some amendments to the partnership agreement, including any amendment that would cause us to be treated as an association taxable as a corporation.

The subordinated units are not entitled to vote on approval of the withdrawal of our general partner or the transfer by our general partner of its general partner interest or incentive distribution rights. Removal of our general partner requires:

- the affirmative vote of two-thirds of all outstanding units voting as a single class; and
- the election of a successor general partner by the holders of a majority of the outstanding common units and subordinated units, voting as separate classes.

Under our partnership agreement, our general partner generally will be permitted to effect amendments to our partnership agreement that do not materially adversely affect unitholders without the approval of any unitholders.

Limited Call Right

If at any time persons other than our general partner and its affiliates do not own more than 20 percent of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then current market price of the common units.

Certain Conflicts of Interest

Our general partner has a legal duty to manage us in a manner beneficial to our unitholders. This legal duty originates in state statutes and judicial decisions and is commonly referred to as a "fiduciary" duty. However, because our general partner is an indirect, wholly owned subsidiary of Penn Virginia, our general partner's officers and directors also have fiduciary duties to manage our general partner's business in a manner beneficial to shareholders of Penn Virginia. Certain officers and directors of our general partner have significant relationships with, and responsibilities to, Penn Virginia. As a result of these relationships, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, on the other hand.

Limits on Fiduciary Responsibilities

Our partnership agreement limits the liability and reduces the fiduciary duties owed by our general partner to unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that might otherwise constitute breaches of our general partner's fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, the partnership agreement permits our general partner to make a number of decisions in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Other provisions of the partnership agreement provide that our general partner's actions must be made in its reasonable discretion. These standards reduce the obligations to which our general partner would otherwise be held.

Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us under the factors previously set forth. In determining whether a transaction or resolution is "fair and reasonable" our general partner may consider the interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty. These standards reduce the obligations to which our general partner would otherwise be held.

In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware General Corporation Law favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We are required to indemnify our general partner and its officers, directors, employees, affiliates, partners, members, agents and trustees to the fullest extent permitted by law against liabilities, costs and expenses incurred by our general partner or these other persons. This indemnification is required if our general partner or any of these persons acted in good faith and in a manner they reasonably believed to be in, or (in the case of a person other than our general partner) not opposed to, our best interests. Indemnification is required for criminal proceedings if our general partner or these other persons had no reasonable cause to believe their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it met these requirements concerning good faith and our best interests.

Competition

Coal

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. Our 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 our lessees having significantly larger financial and operating resources than most of our lessees. Our lessees primarily compete with both large and small producers in Appalachia as well as in the western United States. Our 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 our coal and the prices that our 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 our low sulfur coal and the prices our 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 our 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.

We experience competition in all of our midstream markets. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of our competitors have greater financial resources and access to larger natural gas supplies than we do.

Regulation

Coal

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

While it is not possible to quantify the costs of compliance by our 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 our lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, we do 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 our lessees. The possibility exists that new legislation or regulations may be adopted which have a significant impact on the mining operations of our lessees or their customers' ability to use coal and may require us, our 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 our business. The Clean Air Act directly impacts our 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 our lessees' ability to sell coal, which could have a material effect on our 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, our 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 our coal could be affected, which could have an adverse effect on our 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 our lessees' coal sales, and thereby have an adverse affect on our 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 our coal lessees to us if any of these lessees are not financially capable of fulfilling those obligations. In conjunction with mining the property, our 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 Waste. 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. We could become liable under federal and state Superfund and waste management statutes if our 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***.** Our 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.

Our 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, our 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 our lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on our 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 our lessees' ability to develop new mines, or could require our lessees to modify existing operations, which could have an adverse effect on our coal royalty revenues.

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 our 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 our 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 our lessees' coal production, which could have an adverse affect on our 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, our 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 our 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, our lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In our experience, permits generally are approved within 12 months after a completed application is submitted. In the past, our lessees have generally obtained their mining permits without significant delay. Our 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. Our 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. 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.

Natural Gas Midstream

General Regulation. Our natural gas gathering facilities generally are exempt from the Federal Energy Regulatory Commission's (the "FERC") jurisdiction under the Natural Gas Act of 1938 (the "NGA"), but FERC regulation nevertheless could significantly affect our gathering business and the market for our services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which our 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, our 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. Our operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits us from charging any unduly discriminatory fees for our gathering services. We cannot predict whether our gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

We are 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 our right as an owner of gathering facilities to decide with whom we contract 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 Natural Gas Pipeline Safety Act of 1968, as amended (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 our 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. Our 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 our processing plants and compressor stations and also impose procedural requirements on how we conduct our midstream operations. Such laws and regulations may include requirements that we 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 we are required to obtain or utilize specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We 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 Waste. Our 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 we own or operate, regardless of whether such disposal or release occurred during or prior to our 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," our midstream operations do generate wastes in the course of ordinary operations that may fall within the definition of a "hazardous substance."

Our 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 our facilities.

We currently own or lease 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, we 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. We have ongoing remediation projects underway at several sites, but we do not believe that the costs associated with such cleanups will have a material adverse impact on our operations or revenues.

Water Discharges. Our 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 our systems or facilities could result in fines or penalties as well as significant remedial obligations.

OSHA. Our midstream operations are subject to OSHA. See Item 1, "Business—Regulation—Coal—OSHA."

Employees and Labor Relations

We have no employees. To carry out our operations, our general partner and its affiliates employed 111 employees who directly supported our operations at December 31, 2005. Our general partner considers current employee relations to be favorable.

Available Information

The Partnership's internet address is www.pvresource.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 Audit Committee Charter, and we will provide copies of such documents to any unitholder 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").

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 Business Generally

The amount of cash that we will be able to distribute on our common units principally depends upon the amount of cash we generate from our coal and natural gas midstream businesses.

Under the terms of our partnership agreement, we must pay our general partner's expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash that we will be able to distribute each quarter on our common units principally depends upon the amount of cash we generate from our coal and natural gas midstream businesses. The amount of cash we will generate will fluctuate from quarter to quarter based on, among other things:

- the amount of coal our lessees are able to produce;
- the price at which our lessees are able to sell the coal;
- the lessees' timely receipt of payment from their customers;
- the amount of natural gas transported in our gathering systems;
- the amount of throughput in our processing plants;
- the price of natural gas;

- the price of NGLs;
- the relationship between natural gas and NGL prices;
- the fees we charge and the margins we realize for our midstream services; and
- our hedging activities.

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

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

You should also be aware that the amount of cash we have available for distribution depends primarily upon our 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, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record profits.

We may not be able to fully execute our growth strategy and our results of operations may be adversely affected if we do not successfully integrate the businesses we acquire or if we substantially increase our indebtedness and contingent liabilities.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream and coal assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversify our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, potential joint ventures, stand alone projects or other transactions that we believe will present opportunities to realize synergies and increase our market positions in the coal and midstream businesses.

We may require substantial new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets.

We may be unable to successfully integrate businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our results of operations, cash flows and financial condition. Moreover, acquisitions and business expansions involve numerous risks, including:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets;
- unanticipated costs or liabilities; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, depletion and amortization expenses. As a result, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our business.

Risks Related to Our Coal Business

If our lessees do not manage their operations well, their production volumes and our coal royalty revenues could decrease.

We depend on our lessees to effectively manage their operations on our properties. Our 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 our lessees do not manage their operations well, their production could be reduced, which would result in lower coal royalty revenues to us and could adversely affect our ability to make our quarterly distributions.

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

Our coal royalty revenues are largely dependent on the level of production from our coal reserves achieved by our lessees. The level of our lessees' production is subject to operating conditions or events beyond their or our 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 our 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 our reserves could reduce our coal royalty revenues and adversely affect our ability to make our quarterly distributions.

In addition, our coal royalty revenues are based upon sales of coal by our lessees to their customers. If our 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 our cash flow to be adversely affected and could adversely affect our ability to make our quarterly distributions.

A substantial or extended decline in coal prices could reduce our coal royalty revenues and the value of our coal reserves.

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

We depend on a limited number of primary operators for a significant portion of our coal royalty revenues and the loss of or reduction in production from any of our major lessees could reduce our coal royalty revenues.

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

A failure on the part of our lessees to make coal royalty payments could give us the right to terminate the lease, repossess the property or obtain liquidation damages and/or enforce payment obligations under the lease. If we repossessed any of our properties, we would seek to find a replacement lessee. We may not be able to find a replacement lessee and, if we find a replacement lessee, we 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 we enter 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 us 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.

Our coal business will be adversely affected if we are unable to replace or increase our reserves through acquisitions.

Because our reserves decline as our lessees mine our coal, our future success and growth depends, in part, upon our ability to acquire additional coal reserves that are economically recoverable. If we are unable to negotiate purchase contracts to replace or increase our coal reserves on acceptable terms, our coal royalty revenues will decline as our coal reserves are depleted. In addition, if we are unable to successfully integrate the companies, businesses or properties we are able to acquire, our coal royalty revenues may decline and we could, therefore, experience a material adverse effect on our business, financial condition or results of operations. If we acquire additional coal reserves, there is a possibility that any acquisition could be dilutive to earnings and reduce our ability to make distributions to unitholders or to pay interest on, or the principal of, our debt obligations. Any debt we incur to finance an acquisition may similarly affect our ability to make distributions to unitholders or to pay interest on, or the principal of, our debt obligations. Our ability to make acquisitions in the future also could be limited by restrictions under our 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 ours, depriving us of the ability to receive amounts in excess of the minimum royalty payments.

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

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

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. Our 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 our lessees having significantly larger financial and operating resources than most of our lessees. Our 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 our coal and the prices that our 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 our low sulfur coal and the prices our 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 our coal royalty revenues and adversely affect our ability to make distributions to unitholders and to service our debt obligations.

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

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

Our 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 our lessees to supply coal to their customers. Our lessees' transportation providers may face difficulties in the future and impair the ability of our lessees to supply coal to their customers, thereby resulting in decreased coal royalty revenues to us.

Our lessees could experience labor disruptions, and our lessees' workforces could become increasingly unionized in the future.

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

Our reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our reserves.

Our estimates of our reserves may vary substantially from the actual amounts of coal our lessees may be able to economically recover. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our 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 our experiences in areas where our 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 our 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 our lessees to sell the coal they produce and thereby reduce our coal royalty revenues.

According to the U.S. Department of Energy, domestic electric power generation accounts for approximately 90% 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. We believe 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 our lessees to sell the coal they produce and thereby reduce our 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 our 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 our lessees produce and thereby reducing our coal royalty revenues. Please read Item 1, "Business—Regulation—Coal—Air Emissions."

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

Mine operators, including our 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 our 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 our lessees' ability to economically conduct their mining operations. Limitations on our lessees' ability to conduct their mining operations due to the inability to obtain or renew necessary permits could have an adverse effect on our coal royalty revenues. See Item 1, "Business—Regulation—Coal—Mining Permits and Approvals."

Our 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 our lessees' ability to produce coal, which could have an adverse effect on our coal royalty revenues.

Our 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. Our 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 our lessees' mining operations, either through direct impacts such as new requirements impacting our 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 our 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, we do not believe violations by our 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. Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our 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, our coal royalty revenues and our 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 our lessees' coal production which could have an adverse affect on our coal royalty revenues and our ability to make distributions.

Risks Related to our Midstream Business

The success of our midstream business depends upon our ability to find and contract for new sources of natural gas supply.

In order to maintain or increase throughput levels on our gathering systems and asset utilization rates at our processing plants, we must contract for new natural gas supplies. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our 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 our gathering systems. We 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. We have no control over the level of drilling activity in our areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, we have 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 our midstream assets, including our gathering systems and processing plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. Our cash flows associated with these systems will decline unless we are able to access new supplies of natural gas by connecting additional production to these systems. A material decrease in natural gas production in our areas of operation, as a result of depressed commodity prices or otherwise, would result in a decline in the volume of natural gas we handle, which would reduce our revenues and operating income. In addition, our future growth will depend, in part, upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our currently connected supplies.

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

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

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

We are subject to significant risks due to fluctuations in commodity prices. During 2005, we generated a majority of our gross margin from two types of contractual arrangements under which our 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, we provide gathering and processing services for natural gas received. Under percentage-of-proceeds arrangements, we generally sell the NGLs produced from the processing operations and the remaining residue gas at market prices and remit 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 our results of operations. Under gas purchase/keep-whole arrangements, we generally buy natural gas from producers based upon an index price and then sell 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 our results of operations.

In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. The markets and prices for residue gas and NGLs depend upon factors beyond our 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.

We encounter competition from other midstream companies.

We experience competition in all of our midstream markets. Competition is based on many factors, including geographic proximity to production, costs of connection, available capacity, rates and access to markets. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of our competitors have greater financial resources and access to larger natural gas supplies than we do.

Expanding our midstream business by constructing new gathering systems, pipelines and processing facilities subjects us to construction risks.

One of the ways we may grow our 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 our control and require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule, or at all, or at the budgeted cost. Moreover, our 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 our estimates. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we 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 our expected investment return, which could adversely affect our financial position or results of operations.

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

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way before constructing new pipelines. We may be unable to obtain rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us 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 our cash flows could be reduced.

We are exposed to the credit risk of our midstream customers, and nonpayment or nonperformance by our customers could reduce our cash flows.

We are subject to risk of loss resulting from nonpayment or nonperformance by our customers. We depend on a limited number of customers for a significant portion of our midstream revenue. For 2005, two customers represented 46 percent of our total natural gas midstream revenues and 35 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, us in interconnecting third-party pipelines could cause a reduction of volumes processed, which would adversely affect our revenues and cash flow.

We are 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 our midstream facilities. Similarly, if additional shippers begin transporting volumes of residue gas and NGLs on interconnecting pipelines, our allocations in these pipelines would be reduced. Any reduction in volumes gathered and processed in our facilities would adversely affect our revenues and cash flow.

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 natural gas and NGLs, we periodically enter into natural gas and NGL 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. However, in connection with acquisitions, sometimes our hedges are for longer periods. While intended to reduce the effects of volatile natural gas and NGL prices, such transactions may limit our 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, we 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 our 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 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 natural gas or NGL 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 partners' capital 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.

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

Our 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 our related operations. Our 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 our operations. We are not fully insured against all risks incident to our midstream business. We do not have property insurance on all of our underground pipeline systems that would cover damage to the pipelines. We are 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 our operations and financial condition.

Federal, state or local regulatory measures could adversely affect our 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.

Our natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but FERC regulation nevertheless could significantly affect our gathering business and the market for our services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which our 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, our 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. Our operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits us from charging any unduly discriminatory fees for our gathering services. We cannot predict whether our gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

We are 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 our right as an owner of gathering facilities to decide with whom we contract 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 our 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.

Our midstream business is subject to extensive environmental regulation.

Many of the operations and activities of our 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 our 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 our business activities in many ways, including restricting the manner in which we dispose 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 our midstream business due to our handling of natural gas and other petroleum products, air emissions related to our 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 our pipelines or processing facilities could subject us 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 our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Insurance may not provide sufficient coverage in the event an environmental claim is made.

Risks Related to our Structure

The Partnership and the Operating Company depend on distributions from operating subsidiaries to service their debt obligations.

The Partnership is a holding company with no material operations. The Operating Company holds significant assets, including the equity interests in our principal subsidiaries, Fieldcrest Resources LLC, K Rail LLC, Loadout LLC, PVR Midstream LLC, Suncrest Resources LLC and Wise LLC. If we do not receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations. Our operating subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions which could further limit each operating subsidiary's ability to make distributions to us.

Penn Virginia and its affiliates have conflicts of interest and limited fiduciary responsibilities, which may permit them to favor their own interests to your detriment.

Penn Virginia and its affiliates own an aggregate 37 percent limited partner interest in the Partnership and own and control our general partner. Conflicts of interest may arise between Penn Virginia and its affiliates, including our general partner, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of the unitholders. These conflicts include, among others, the following situations:

- Some officers of Penn Virginia, who provide services to us, also devote significant time to the businesses of Penn Virginia and are compensated by Penn Virginia for the services they provide.
- Neither our partnership agreement nor any other agreement requires Penn Virginia to pursue a business strategy that favors us. Penn Virginia's directors and officers have a fiduciary duty to make decisions in the best interests of the shareholders of Penn Virginia.
- Penn Virginia and its affiliates may engage in limited competition with us.
- Our general partner is allowed to take into account the interests of parties other than us, such as Penn Virginia, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to the unitholders.
- Our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. Any purchase of units is deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.
- Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves, each of which can affect the amount of cash that is distributed to unitholders.
- Our general partner determines which costs incurred by Penn Virginia and its affiliates are reimbursable by us.
- Our partnership agreement does not restrict our general partner from causing us to pay our general partner or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Unitholders have less ability to elect or remove management or effect a change of control than holders of common stock in a corporation.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its board of directors and have no right to elect our general partner or the directors of our general partner on an annual or other continuing basis.

The board of directors of our general partner is chosen by Penn Virginia. In addition to the fiduciary duty our general partner has to manage our partnership in a manner beneficial to us and the unitholders, the directors of our general partner also have a fiduciary duty to manage our general partner in a manner beneficial to Penn Virginia.

Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have limited ability to remove our general partner. First, our general partner generally may not be removed except upon the vote of the holders of two-thirds of the outstanding units voting together as a single class. Because our general partner and its affiliates control approximately 37 percent of all the units, our general partner currently cannot be removed without the consent of our general partner and its affiliates. Additionally, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units which would otherwise have continued until we met certain distribution and performance tests.

Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders' dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20 percent or more of any class of units then outstanding, other than our general partner, its affiliates and their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Finally, Peabody has a change of control repurchase right as a result of our acquisition of certain coal reserves of Peabody in December 2002. For as long as either of our leases with Peabody relating to the coal reserves purchased in the acquisition is in effect, Peabody has the right, upon a change in control (as defined in the purchase agreement executed in connection with the acquisition) of us, Penn Virginia or our general partner, to purchase all of the reserves and other related assets that they sold to us, to the extent those assets are then owned by us, at a price to be agreed upon at that time or, if we are unable to agree, at the fair market value as determined based on the average valuations of three designated investment banks.

Any or all of these provisions may discourage a person or group from attempting to remove our general partner or otherwise change our management or effect a change of control. As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the owner of our general partner from transferring its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to you.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of our general partner, for expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions to you. Our general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us other services for which we will be charged fees as determined by our general partner.

Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to unitholders.

Our general partner has a limited call right that may require unitholders to sell units at an undesirable time or price.

If at any time persons other than our general partner and its affiliates do not own more than 20 percent of the common units then outstanding, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than their then current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under the partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Tax Risks to Common Unitholders

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to you.

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35 percent, and would likely pay state income taxes at varying rates. Distributions to you would generally be taxed again to you as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, the cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the after-tax return to you, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

Current law may change so as to cause us to be taxed as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect the impact of that law on us.

You may be required to pay taxes even if you do not receive any cash distributions.

You will be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your share of our taxable income.

Tax gain or loss on disposition of common units could be different than expected.

If you sell your common units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. Should the IRS successfully contest some positions we take, you could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. Also, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities, regulated investment companies and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and foreign persons raises issues unique to them. For example, a significant amount of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Regulated investment companies are subject to certain asset diversification tests and are limited in the amount that they may invest in the Partnership. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S. federal income tax rate for individuals, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We are registered as a tax shelter. This may increase the risk of an IRS audit of us or a unitholder.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 01309000001. The IRS requires that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a one percent profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return.

We will treat each purchaser of common units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that do not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to your tax returns.

You will likely be subject to state and local taxes in states where you do not live as a result of an investment in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not reside in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. It is your responsibility to file all United States federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

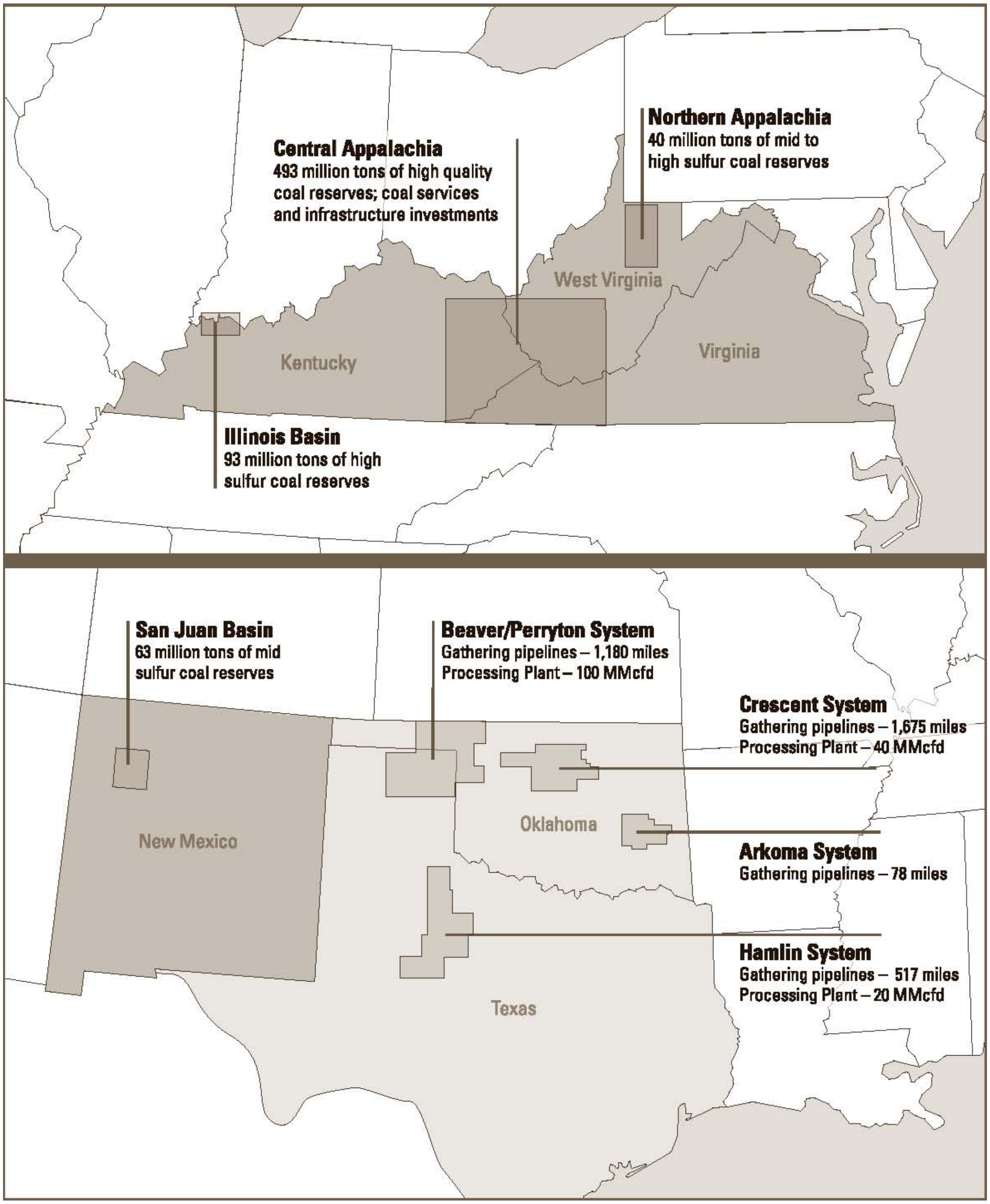
Item 1B *Unresolved Staff Comments*

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*

Title to Properties

The following maps show the general locations of our coal reserves, coal services and infrastructure investments and our natural gas gathering and processing systems:



We believe that we have satisfactory title to all of our properties and the associated coal reserves in accordance with standards generally accepted in the coal and natural gas midstream industries.

Facilities

Our general partner provides all of our office space, except for a field office that we own near Charleston, West Virginia.

Coal Reserves and Production

As of December 31, 2005, our coal reserves were located on approximately 336,000 acres, including fee and leased acreage, in Kentucky, New Mexico, Virginia and West Virginia. Our coal reserves are in various surface and underground mine seams. As of December 31, 2005, we 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. All of the estimates of our reserves are classified as proven and probable reserves. Proven and probable reserves are defined as follows:

Proven Reserves—Proven reserves are reserves for which: (a) 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 Reserves—Probable 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, we perform additional exploration to ensure the continuity and mineability of the 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 our reserves are high in energy content, low in sulfur and suitable for either the steam or metallurgical market.

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.

Our lessees mine coal using both underground and surface methods. Our lessees currently operate 28 surface mines and 39 underground mines. Approximately 61 percent of the coal produced from our properties in 2005 came from underground mines and 39 percent came from surface mines. Most of our lessees use the continuous mining method in all of their underground mines located on our properties. In continuous mining, main airways and transportation entries are developed and remote-controlled continuous miners extract coal from "rooms," leaving "pillars" to support the roof. Shuttle cars transport coal to a conveyor belt for transportation to the surface. In several underground mines, our lessees use two continuous miners running at the same time, also known as a supersection, to improve productivity and reduce unit costs.

Two of our lessees use the longwall mining method to mine underground reserves. Longwall mining uses hydraulic jacks or shields, varying from four feet to twelve feet in height, to support the roof of the mine while a mobile cutting shearer advances through the coal. Chain conveyors then move the coal to a standard deep mine conveyor belt system for delivery to the surface. Continuous mining is used to develop access to long rectangular panels of coal that are mined with longwall equipment, allowing controlled caving behind the advancing machinery. Longwall mining is typically highly productive when used for large blocks of medium to thick coal seams.

Surface mining methods used by our lessees include auger and highwall mining to enhance production, improve reserve recovery and reduce unit costs. On our San Juan Basin property, a combination of the dragline and truck-and-shovel surface mining methods is used to mine the coal. Dragline and truck-and-shovel mining uses large capacity machines to remove overburden to expose the coal seams. Wheel loaders then load the coal in haul trucks for transportation to a loading facility.

Our lessees' customers are primarily utilities. Coal produced from our properties is transported by rail, barge and truck, or a combination of these means of transportation. Coal from the Virginia portion of the Wise property and the Buchanan property is primarily shipped to electric utilities in the Southeast by the Norfolk Southern railroad. Coal from the Kentucky portion of the Wise property is primarily shipped to electric utilities in the Southeast by the CSX railroad. Coal from the Coal River and Spruce Laurel properties is shipped to steam and metallurgical customers by the CSX railroad, by barge along the Kanawha River and by truck or by a combination thereof. Coal from the northern Appalachia property is shipped by barge on the Monongahela River, by truck and by the CSX and Norfolk Southern railroads. Coal from the Illinois Basin property is shipped by barge on the Green River and by truck. Coal from the San Juan Basin property is shipped to steam markets in New Mexico and Arizona by the Burlington Northern Santa Fe railroad. All of our properties contain and have access to numerous roads and state or interstate highways.

The following table sets forth production data and reserve information with respect to each of our 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

Of the 689.1 million tons of proven and probable coal reserves to which we had rights as of December 31, 2005, we owned the mineral interests and the related surface rights to 389.4 million tons, or 56 percent, and we owned only the mineral interests to 219.9 million tons, or 32 percent. We lease the mineral rights to the remaining 79.8 million tons, or 12 percent, from unaffiliated third parties and, in turn, sublease these reserves to our lessees. For the reserves we lease from third parties, we pay royalties to the owner based on the amount of coal produced from the lease reserves. Additionally, in some instances, we purchase surface rights or otherwise compensate surface right owners for mining activities on their properties. In 2005, our aggregated expenses to third-party surface and mineral owners were $4.2 million.

The following table sets forth the coal reserves we own and lease with respect to each of our 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

Our reserve estimates are prepared from geological data assembled and analyzed by our 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.

We classify low sulfur coal as coal with a sulfur content of less than 1.0 percent, medium sulfur coal as coal with a sulfur content between 1.0 percent and 1.5 percent and high sulfur coal as coal with a sulfur content of greater than 1.5 percent. Compliance coal is that portion of low sulfur coal that meets compliance standards for the Clean Air Act. As of December 31, 2005, approximately 25 percent of our reserves met compliance standards for the Clean Air Act. The following table sets forth our estimate of the sulfur content and the typical clean coal quality of our recoverable coal reserves at December 31, 2005:

Property	Type of Coal	Compliance(1)	Low Sulfur (2)	Medium Sulfur	High Sulfur	Sulfur Unclassified	Total	Btu per Pound (3)	Sulfur (%)	Ash (%)
			Sulfur Content — Reserves as of 12/31/05					Typical Clean Coal Quality — Heat Content		
			(tons in millions)							
Central Appalachia	Steam/Metallurgical	175.6	298.2	127.5	32.8	35.2	493.7	12,863	1.05	7.07
Northern Appalachia	Steam/Metallurgical	0.0	0.0	0.0	39.6	0.0	39.6	12,900	2.58	8.80
Illinois Basin	Steam/Metallurgical	0.0	0.0	0.0	92.9	0.0	92.8	11,005	3.90	11.38
San Juan Basin	Steam	0.0	35.9	21.4	5.6	0.0	63.0	9,200	0.89	17.80
Total		175.6	334.1	148.9	170.9	35.2	689.1			

(1) Compliance coal is low sulfur coal which, when burned, emits less than 1.2 pounds of sulfur dioxide per million Btu. Compliance coal meets the sulfur dioxide emission standards imposed by the Clean Air Act without blending in other coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.
(2) Includes compliance coal.
(3) As-received Btu per pound includes the weight of moisture in the coal on an as sold basis.

The following table shows the reserves we lease to mine operators by property:

Property	Controlled	Leased (Out)	Percentage Leased (Out)
	Proven and Probable Reserves As of December 31, 2005		
	(tons in millions)		
Central Appalachia	493.7	400.2	81%
Northern Appalachia	39.6	39.2	99%
Illinois Basin	92.8	43.1	46%
San Juan Basin	63.0	62.9	100%
Total	689.1	545.4	79%

Coal Preparation and Loading Facilities

We generate revenues from fees we charge to our lessees for the use of our coal preparation and loading facilities. The facilities provide efficient methods to enhance lessee production levels and exploit our reserves. Historically, the majority of these fees have been generated by our unit train loadout facility on our central Appalachia property, which accommodates 108 car unit trains that can be loaded in approximately four hours. Some of our lessees utilize the unit train loadout facility to reduce the delivery costs incurred by their customers. The coal service facility we purchased in November 2002 on our Coal River property in West Virginia (formerly referred to as “Fork Creek”) began operations late in the third quarter of 2003. In the first quarter of 2004, we placed into service a newly constructed coal loadout facility for another lessee in West Virginia for $4.4 million. We are currently constructing a new preparation and loading facility on property we acquired in 2005 in eastern Kentucky.

Natural Gas Midstream Systems

Our natural gas midstream assets are primarily located in the mid-continent area of Oklahoma and the panhandle of Texas. We own and operate 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. Our 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. We own, lease or have rights-of-way to the properties where the majority of our midstream facilities are located. We believe we have sufficient rights-of-way to accommodate our gathering systems and pipelines.

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

Asset	Type	Approximate Length (Miles)	Approximate Wells Connected	Processing Capacity (Mmcfd) (1)	Ten Months Ended December 31, 2005 (3) Average Plant Throughput (Mmcfd)	Ten Months Ended December 31, 2005 (3) 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.

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, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Market Information

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

Quarter Ended	High	Low
December 31, 2005	$ 55.98	$ 50.53
September 30, 2005	$ 54.20	$ 47.90
June 30, 2005	$ 52.90	$ 43.32
March 31, 2005	$ 57.15	$ 47.68
December 31, 2004	$ 54.30	$ 39.30
September 30, 2004	$ 41.00	$ 35.75
June 30, 2004	$ 36.30	$ 31.65
March 31, 2004	$ 37.10	$ 30.00

We issued subordinated units in October 2001, all of which are held by two affiliates of our general partner. There is no established public trading market for the subordinated units.

Equity Holders

As of March 8, 2006, there were approximately 175 record holders and approximately 17,000 beneficial owners (held in street name) of our common units and two holders of our subordinated units.

Distributions

For the year ended December 31, 2005, we paid cash distributions of $2.4825 per common and subordinated unit. For 2006, we expect to pay distributions of at least $2.80 per common unit and subordinated unit.

The quarterly cash distributions paid in 2005 and 2004 were as follows:

Period Covered by Distribution	Record Date	Payment Date	Amount Per Unit
Third quarter 2005	November 3, 2005	November 14, 2005	$0.6500
Second quarter 2005	August 2, 2005	August 12, 2005	$0.6500
First quarter 2005	May 3, 2005	May 13, 2005	$0.6200
Fourth quarter 2004	February 4, 2005	February 14, 2005	$0.5625
Third quarter 2004	November 3, 2004	November 12, 2004	$0.5400
Second quarter 2004	August 4, 2004	August 13, 2004	$0.5400
First quarter 2004	May 5, 2004	May 14, 2004	$0.5200
Fourth quarter 2003	January 30, 2004	February 13, 2004	$0.5200

If cash distributions per unit exceed $0.55 in any quarter, our general partner will receive a higher percentage of the cash we distribute in excess of that amount in increasing percentages up to 50 percent. See Item 1, "Business—Partnership Distributions—Incentive Distribution Rights." On February 14, 2006, the board of directors of our general partner paid a cash distribution with respect to the fourth quarter of 2005 of $0.70 per unit, exceeding the $0.55 threshold.

There is no guarantee that we will pay quarterly cash distributions on the common units in any quarter, and we will be prohibited from making any distributions to unitholders if it would cause an event of default under our revolving credit facility. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Item 6 ***Selected Financial Data***

On October 30, 2001, we completed the IPO, whereby we became the successor to the business of the Penn Virginia Coal Business (predecessor). For the purposes of this selected financial data, we refer to the Penn Virginia Coal Business for the periods prior to October 30, 2001, and to Penn Virginia Resource Partners, L.P. for the periods subsequent to October 30, 2001. The following selected historical financial information was derived from the financial statements of the Partnership as of December 31, 2005, 2004, 2003, 2002 and 2001, and for the five years then ended. The selected financial data should be read in conjunction with the combined financial statements, including the notes thereto, and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2005 (1)	**2004**	**2003**	**2002**	**2001**
	(in thousands, except per unit data)				
Revenues	$ 446,348	$ 75,630	$ 55,642	$ 38,608	$ 37,513
Expenses	$ 368,258	$ 35,111	$ 29,082	$ 14,181	$ 12,355
Operating income	$ 78,090	$ 40,519	$ 26,560	$ 24,427	$ 25,158
Net income	$ 51,161	$ 34,315	$ 22,690	$ 24,686	$ 16,099
Net income per limited partner unit, basic and diluted (2)	$ 2.43	$ 1.86	$ 1.24	$ 1.57	$ 0.24
Total assets (3)	$ 657,879	$ 284,435	$ 259,892	$ 266,575	$ 162,638
Long-term debt	$ 246,846	$ 112,926	$ 90,286	$ 90,887	$ 43,387
Cash flows provided by operating activities	$ 93,712	$ 54,782	$ 41,077	$ 30,342	$ 21,595
Distributions paid	$ (51,949)	$ (39,191)	$ (36,708)	$ (28,723)	$ —
Distributions paid per unit	$ 2.48	$ 2.12	$ 2.06	$ 1.84	$ —

(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) Net income per unit relates to the period from October 31, 2001 (commencement of operations) to December 31, 2001.
(3) Total assets in 2005 reflect the Cantera Acquisition.

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

The following review of the financial condition and results of operations of Penn Virginia Resource Partners, L.P. 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 a Delaware limited partnership formed by Penn Virginia in 2001 primarily to engage in the business of managing coal properties and related assets in the United States. Penn Virginia contributed its coal properties and related assets to us and, effective with the closing of the IPO in October 2001, our common units began trading publicly on the New York Stock Exchange under the symbol "PVR."

Both in our current limited partnership form and in our previous corporate form, we have managed coal properties since 1882. Since the acquisition of a natural gas midstream business in March 2005, we conduct operations in two business segments: coal and natural gas midstream.

Overview of 2005 Performance

Operating income for 2005 was $78.1 million. The coal segment contributed $61.7 million, or 79 percent, to operating income, and the natural gas midstream segment contributed $16.3 million, or 21 percent. A description of each of our reportable segments follows:

- 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.

Coal Segment

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

We also earn coal services revenues related to our ownership of coal preparation plants and coal loading facilities. Coal services revenues increased to $5.2 million in 2005 from $3.8 million in 2004. We believe that these types of fee-based infrastructure assets provide good investment and cash flow opportunities for us, and we continue 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, we own and operate a significant set of midstream assets located primarily 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. Our 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 our cash flows into another long-lived asset base.

For the ten months ended December 31, 2005, our midstream operations generated a gross processing margin of $44.7 million, consisting of midstream revenues minus the cost of gas purchased. Inlet volumes at our 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

Coal Segment

Coal River Acquisition. In March 2005, we 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 acquisition was funded with long-term debt under our revolving credit facility. The coal reserves are predominantly low sulfur and high BTU content, and development will occur in conjunction with our 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 with current net production of approximately 0.2 Bcfe on an annualized basis.

Alloy Acquisition. In April 2005, we 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 our property commenced production. The seller remained on the property as the lessee and operator. The Alloy Acquisition was funded with long-term debt under our revolving credit facility.

Wayland Acquisition. In July 2005, we 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 our issuance to the seller of approximately 209,000 common units. In addition, we assumed $0.7 million of liabilities related to the acquired property. During the third quarter of 2005, we began constructing a new preparation plant and unit train coal loading facility on the property, which we expect to complete during the second quarter of 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 limited basis during construction of the preparation and loading facility. After completion of the facility, we expect the operator's production from the property to increase to approximately one million tons of coal per year in 2007. We also expect to earn fees from third party operators for coal processed from adjacent properties.

Green River Acquisition. In July 2005, we 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 we assumed $3.3 million of deferred income. This coal reserve acquisition is our first in the Illinois Basin and was funded with long-term debt under our revolving credit facility. Currently, approximately 45 million tons of these coal reserves are leased to affiliates of Peabody. We expect 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, we 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 our 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. We recognized equity earnings of $1.1 million in 2005 and $0.4 million in 2004 related to our ownership in the joint venture. We 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, we completed our 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 we funded with a $110 million term loan and with long-term debt under our revolving credit facility. We used the proceeds from our sale of common units in a subsequent public offering in March 2005 to repay our term loan in full and to reduce outstanding indebtedness under our revolving credit facility. See Note 3 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.

Natural Gas Midstream Revenues

Revenue from the sale of NGLs and residue gas is recognized when the NGLs and residue gas produced at our 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 our lessees and the corresponding revenues from those sales. Since we do not operate any coal mines, we do not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. 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 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 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.

Depletion

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. Proven and probable reserves have been estimated by our own geologists and outside consultants. Our estimates of coal reserves are updated annually and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. We estimate timber inventory using statistical information and data obtained from physical measurements, site maps, photo-types and other information gathering techniques. These estimates are updated annually and may result in adjustments of timber volumes and depletion rates, which are recognized prospectively.

Goodwill

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 tested for impairment at least annually. Accordingly, we do not amortize goodwill. We test goodwill for impairment during the fourth quarter of each fiscal year. Based on the results of our test during the fourth quarter of 2005, no goodwill impairment was recognized in 2005.

Intangibles

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 15 years, the period in which benefits are derived from the contracts, relationships and rights-of-way, and will be reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

Liquidity and Capital Resources

Since the closing of the IPO in October 2001, cash generated from operations and our borrowing capacity, supplemented by proceeds from the issuance of new common units, have been sufficient to meet our scheduled distributions, working capital requirements and capital expenditures. Our primary cash requirements consist of quarterly distributions to our general partner and unitholders, normal operating expenses, interest and principal payments on our long-term debt and acquisitions of new assets or businesses.

Cash Flows

The overall increase in cash provided by operations in 2005 compared to 2004 was primarily attributable to higher average gross coal royalties per ton and accretive cash flows from our newly acquired natural gas midstream business. The overall increase in cash provided by operations in 2004 compared to 2003 was largely due to increased production by our lessees and higher coal royalty rates.

We made cash investments in 2005 primarily for the Cantera Acquisition and coal reserve acquisitions. Other investments in 2005 included a $4.1 million purchase of railcars that we previously leased and $4.4 million of gathering system additions. Cash investments in 2004 primarily related to our investment in the coal handling joint venture with Massey, which has been accounted for as an equity investment. Cash investments in 2003 primarily related to our construction of a new coal loading facility on our Coal River property in West Virginia.

Capital expenditures, including noncash items, for each of the three years ended December 31, 2005, were as follows:

	2005	2004	2003
		(in thousands)	
Coal			
Coal reserve and lease acquisitions (1) (2)	$ 106,489	$ 1,293	$ 6,330
Acquisition of coal handling joint venture interest	—	28,442	—
Support equipment and facilities (3)	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	—	—
Total capital expenditures	$ 319,308	$ 30,590	$ 10,458

(1) 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 common units and $0.7 million of liabilities assumed. Amount in 2005 also includes the noncash portion of the Green River Acquisition, in which we 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 our northern Appalachia properties in exchange for equity issued in the form of common and Class B units.

(2) Amount in 2005 includes $0.4 million of noncash expenditures due to the timing of payment of invoices.

(3) Amount in 2005 includes $0.8 million of noncash expenditures due to the timing of payment of invoices.

To finance our 2005 acquisitions, we borrowed $137.2 million, net of repayments, received proceeds of $126.4 million from our secondary public offering and received a $2.6 million contribution from our general partner. To finance our equity investment in the Massey coal handling joint venture in 2004, we borrowed $26.0 million, net of repayments. In 2003, we received $90.0 million in proceeds from a private placement of senior unsecured notes, which we used to repay a $43.4 million term loan and to repay most of the outstanding debt on our revolving credit facility at the time. Distributions to partners increased to $51.9 million in 2005 from $39.2 million in 2004 and $36.7 million in 2003 because we increased the quarterly unit distribution.

Long-Term Debt

As of December 31, 2005, we had outstanding borrowings of $255.0 million, consisting of $172.0 million borrowed under our revolving credit facility and $83.0 million of senior unsecured notes (the "Notes"). The current portion of the Notes as of December 31, 2005, was $8.1 million.

Revolving Credit Facility. Concurrent with the closing of the Cantera Acquisition in March 2005, the Operating Company, 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. The new agreement consisted of a $150 million revolving credit facility (the "Revolver") that matures in March 2010 and a $110 million term loan. A portion of the Revolver and the term loan were used to fund the Cantera Acquisition and to repay borrowings under our previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million common units in March 2005 and a $2.6 million contribution from our general partner were used to repay the $110 million term loan and a portion of the amount outstanding under the Revolver. In the fourth quarter of 2004, we 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 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. In 2005, we incurred commitment fees of $0.4 million on the unused portion of the Revolver.

In July 2005, we amended our credit agreement to increase the size of the commitment under the Revolver from $150 million to $300 million and to increase a one-time option (upon receipt by the credit facility's administrative agent of commitments from one or more lenders) to expand the 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 our ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if we select the base rate borrowing option under the credit agreement or at a rate derived from the London Interbank Offering Rate ("LIBOR") plus an applicable margin ranging from 1.00 percent to 2.00 percent if we select the LIBOR-based borrowing option. The other terms of the credit agreement remained unchanged.

The financial covenants under the Revolver require us to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted our borrowing capacity under the Revolver to approximately $106.5 million as of December 31, 2005. The Revolver prohibits us from making distributions to unitholders and distributions in excess of available cash if any potential default or event of default, as defined in the Revolver, occurs or would result from the distribution. In addition, the Revolver contains various 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.

Senior Unsecured Notes. As of December 31, 2005, we owed $83.0 million under our Notes. The 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 Notes contain various covenants similar to those contained in the Revolver. The Notes rank pari passu in right of payment with all other unsecured indebtedness, including the Revolver. As of December 31, 2005, we were in compliance with all of our covenants under the Notes.

In conjunction with the closing of the Cantera Acquisition, we amended the Notes to allow us 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, we agreed to a 0.25 percent increase in the fixed interest rate on the Notes, from 5.77 percent to 6.02 percent. The amendment to the Notes also requires that we obtain an annual confirmation of our credit rating, with a 1.00 percent increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. On March 15, 2005, our investment grade credit rating was confirmed by Dominion Bond Rating Services.

Interest Rate Swaps. In September 2005, we 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 Revolver until March 2010 (the "Revolver Swaps"). We pay 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 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 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 Revolver borrowings covered by the Revolver Swaps was 5.47 percent at December 31, 2005.

In March 2003, we 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 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 us 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 Notes using the effective interest rate method.

Future Capital Needs and Commitments

Part of our strategy is to make acquisitions which increase cash available for distribution to our 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. Our ability to make these acquisitions in the future will depend in part on the availability of debt financing and on our 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 our financial condition and credit rating at the time.

We anticipate making capital expenditures, excluding acquisitions, in 2006 of $16 to $18 million for coal services related projects and other property and equipment and $8 to $10 million for natural gas midstream system expansion projects. Management believes that cash flow provided by operating activities will be sufficient to fund these capital expenditures. We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities. Short-term cash requirements, such as operating expenses and quarterly distributions to our general partner and unitholders, are expected to be funded through operating cash flows.

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	$ 172,000	$ —	$ —	$ 172,000	$ —
Senior unsecured notes	83,700	8,300	23,700	27,500	24,200
Rental commitments (1)	3,751	934	1,629	1,188	—
Total contractual cash obligations (2)	$ 259,451	$ 9,234	$ 5,329	$ 200,688	$ 24,200

(1) Our rental commitments primarily relate to reserve-based properties which are, or are intended to be, subleased by us 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. See Item 1A, “Risk Factors.” We believe that the obligation after five years cannot be estimated with certainty; however, based on historical trends, we believe that we will incur approximately $0.6 million in rental commitments in perpetuity until the reserves have been exhausted.

(2) The total contractual cash obligations do not include general partner reimbursement. Our general partner is entitled to receive reimbursement of direct and indirect expenses incurred on our behalf until the Partnership has been dissolved.

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 unit data)		
Revenues	$ 446.3	$ 75.6	$ 55.6
Expenses	$ 368.3	$ 35.1	$ 29.1
Operating income	$ 78.1	$ 40.5	$ 26.6
Net income	$ 51.2	$ 34.3	$ 22.7
Net income per limited partner unit, basic and diluted	$ 2.43	$ 1.86	$ 1.24
Cash flows provided by operating activities	$ 93.7	$ 54.8	$ 41.1

The increase in 2005 net income compared to 2004 net income was primarily attributable to increased operating income, partially offset by a $14.0 million noncash net charge to earnings for unrealized losses on derivatives in our natural gas midstream segment and a $6.7 million increase in interest expense. Operating income increased in 2005 primarily due to increased coal royalty revenues resulting from higher commodity prices and related services income and the contribution of the natural gas midstream segment that was acquired in March 2005.

Coal Segment

The coal segment includes our coal reserves, timber assets and other land assets. We enter into leases with various third-party operators for the right to mine coal reserves on our properties in exchange for royalty payments. We do not operate any mines, but rather lease our coal reserves to various mining operators in exchange for royalty payments. In addition to coal royalty revenues, we generate coal services revenues from fees charged to lessees for the use of coal preparation and loading facilities. We also generate revenues from the sale of standing timber on our properties, the collection of wheelage fees and oil and natural gas well royalties.

Coal royalties are impacted by several factors that we 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 our lessees or their customers' ability to use coal and which may require us, our lessees or our lessee's customers to change operations significantly or incur substantial costs.

Operations and Financial Summary – Coal Segment

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

	2005	2004	% Change
Financial Highlights	(in thousands, except as noted)		
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%
Operating costs and expenses			
Operating	5,755	7,224	(20%)
Taxes other than income	1,129	948	19%
General and administrative	9,237	8,307	11%
Depreciation, depletion and amortization	17,890	18,632	(4%)
Total operating expenses	34,011	35,111	(3%)
Operating income	$ 61,744	$ 40,519	52%
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 from certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by our lessees decreased primarily due to a loss of production resulting from one lessee's longwall mining operation moving off of our 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 we acquired a 50 percent interest 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. We received approximately $1.3 million of additional wheelage fees primarily as a result of the Alloy Acquisition in April 2005. We 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. We 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 in 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 depreciation, depletion and amortization ("DD&A") expense is consistent with the decrease in production.

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

	2004	2003	% Change
Financial Highlights	(in thousands, except as noted)		
Revenues			
Coal royalties	$ 69,643	$ 50,312	38%
Coal services	3,787	2,111	79%
Other	2,200	3,219	(32%)
Total revenues	75,630	55,642	36%
Operating costs and 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 our 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 our subleased central Appalachia properties from an adjacent third party property. The addition of a new mine operator and new mines in our 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 we 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 our lessees. The amount recognized in 2003 primarily related to four leases. Each of these leases was assigned to a new lessee approved by us. 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 our 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 our subleased properties. Production from subleased properties increased by 74 percent to 6.8 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 our Coal River property for which we had been responsible since the bankruptcy of our 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 our coal services facilities which began operations in July 2003 and February 2004.

Natural Gas Midstream Segment

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

The natural gas 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 natural gas 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 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 – Natural Gas 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 operating 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 our gas processing plants and the purchase and resale of natural gas not connected to our gathering systems and processing plants. The average realized sales price was $8.97 per Mcf in 2005. Natural gas inlet volumes at our 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 our 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.

Other

Interest Expense. Interest expense for 2005 increased compared to 2004 primarily due to interest incurred on additional borrowings to finance the Cantera Acquisition and coal property acquisitions in 2005. The increase in interest expense from 2003 to 2004 was primarily due to higher debt levels resulting from the coal handling joint venture investment in July 2004 and bridge loan issue costs that were expensed upon the termination in December 2004 of the bridge loan agreement which we entered into during the fourth quarter of 2004 in anticipation of the Cantera Acquisition.

Interest Income. Interest income changed only slightly from 2004 to 2005. In June 2005, a note receivable matured, resulting in half a year of interest income compared to a full year in 2004. This decrease was offset by interest income earned on cash balances in our new natural gas midstream segment. Interest income decreased from 2003 to 2004 primarily due to the declining principal balance on our note receivable.

Unrealized Loss on Derivatives. The noncash unrealized loss on derivatives of $14.0 million in 2005 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 $0.6 million noncash net unrealized gain for changes in effectiveness of open commodity price hedges related to the natural gas midstream segment. The $13.9 million unrealized loss primarily represented the change in the market value of derivative agreements between the time we entered into the agreements in January 2005 and the time they qualified for hedge accounting after closing the Cantera Acquisition in March 2005. When we agreed to acquire Cantera, we wanted to ensure an acceptable return on the investment. We 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 we will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period.

Environmental

The operations of our coal lessees and our 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 our 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 us against any and all future environmental liabilities. We regularly visit coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of our coal lessees and our natural gas midstream segment comply with existing regulations and does not expect any material impact on our financial condition or results of operations.

As of December 31, 2005 and 2004, our environmental liabilities included $2.5 million and $1.5 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural gas midstream businesses. We have 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. The environmental liabilities are not covered by our indemnification agreement with Penn Virginia.

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

Recent Accounting Pronouncements

See Note 2 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*

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and NGL, crude oil, natural gas and coal price risks.

We are also indirectly exposed to the credit risk of our lessees. If our lessees become financially insolvent, our lessees may not be able to continue operating or meeting their minimum lease payment obligations. As a result, our coal royalty revenues could decrease due to lower production volumes.

As of December 31, 2005, our $83.0 million of outstanding indebtedness under the Notes carried a fixed interest rate throughout its term. We 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. The interest rate swap was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by us to the counterparty in July 2005.

As of December 31, 2005, our $172.0 million of outstanding indebtedness under the Revolver carried a variable interest rate throughout its term. We executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under the 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.

When we agreed to acquire Cantera, we 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 for the unrealized loss on these derivatives. Subsequent to the Cantera Acquisition, we formally 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 us to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and we will be required to record the ineffective portion of the agreements in our net income for the respective period. For 2005, we 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 related to the derivative agreements will occur monthly over the life of the agreements, and we will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period. In addition, we entered into derivative agreements for NGLs and natural gas to further protect our margins subsequent to the Cantera Acquisition. These derivative agreements have been designated as cash flow hedges. See Note 8 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.

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

PENN VIRGINIA RESOURCES, L.P. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Penn Virginia Resource Partners, L.P.:

We have audited the accompanying consolidated balance sheets of Penn Virginia Resource Partners, L.P., a Delaware limited partnership, and subsidiaries (collectively "the Partnership") as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital 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 Partnership'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 Resource Partners, L.P. 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 2 to the consolidated financial statements, effective January 1, 2003, the Partnership 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 Partnership'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

To the Partners of Penn Virginia Resource Partners L.P.:

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 Resource Partners, L.P. and subsidiaries (collectively the "Partnership") 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 Partnership'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 Partnership'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 Partnership 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 Partnership 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 Partnership'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 37 percent of the Partnership's total assets, as of December 31, 2005, and PVR Midstream LLC's total revenues were $350.6 million, or approximately 79 percent of the Partnership's total revenues, for the year ended December 31, 2005. Our audit of internal control over financial reporting of the Partnership 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 Partnership as of December 31, 2005 and 2004, and the related consolidated statements of income, partners' capital 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 RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per unit amounts)

	Year Ended December 31,		
	2005	**2004**	**2003**
Revenues			
Natural gas midstream	$ 348,657	$ —	$ —
Coal royalties	82,725	69,643	50,312
Coal services	5,230	3,787	2,111
Other	9,736	2,200	3,219
Total revenues	446,348	75,630	55,642
Expenses			
Cost of gas purchased	303,912	—	—
Operating	15,102	7,224	4,235
Taxes other than income	2,397	948	1,256
General and administrative	16,219	8,307	7,013
Depreciation, depletion and amortization	30,628	18,632	16,578
Total operating costs and expenses	368,258	35,111	29,082
Operating income	78,090	40,519	26,560
Other income (expense)			
Interest expense	(14,054)	(7,267)	(4,986)
Interest income	1,149	1,063	1,223
Unrealized loss on derivatives	(14,024)	—	—
Income before cumulative effect of change in accounting principle	51,161	34,315	22,797
Cumulative effect of change in account principle	—	—	(107)
Net income	$ 51,161	$ 34,315	$ 22,690
General partner's interest in net income	$ 2,122	$ 686	$ 454
Limited partners' interest in net income	$ 49,039	$ 33,629	$ 22,236
Basic and diluted net income per limited partner unit, common and subordinated:			
Income before cumulative effect of change in accounting principle	$ 2.43	$ 1.86	$ 1.25
Cumulative effect of change in accounting principle	—	—	(0.01)
Net income per limited partner unit	$ 2.43	$ 1.86	$ 1.24
Weighted average number of units outstanding, basic and diluted:			
Common	14,732	10,739	10,291
Subordinated	5,419	7,331	7,650

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 23,193	$ 20,997
Accounts receivable	76,398	8,668
Derivative assets	10,235	—
Other current assets	2,724	541
Total current assets	112,550	30,206
Property, plant and equipment	535,040	271,546
Accumulated depreciation, depletion and amortization	(76,258)	(49,931)
Net property, plant and equipment	458,782	221,615
Equity investments	26,672	27,881
Goodwill	7,718	—
Intangibles, net	38,051	—
Derivative assets	8,536	—
Other long-term assets	5,570	4,733
Total assets	$ 657,879	$ 284,435
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable	$ 58,216	$ 1,046
Accrued liabilities	9,788	2,943
Current portion of long-term debt	8,108	4,800
Deferred income	5,073	1,207
Derivative liabilities	20,700	—
Total current liabilities	101,885	9,996
Deferred income	10,194	8,726
Other liabilities	3,749	2,803
Derivative liabilities	11,246	—
Long-term debt	246,846	112,926
Commitments and contingencies (Note 15)		
Partners' capital		
Common units (16,997 thousand units in 2005 and 12,337 thousand units in 2004)	296,038	164,738
Subordinated units (3,825 thousand units in 2005 and 5,737 thousand units in 2004)	(10,440)	(15,032)
General partner interest	3,252	278
Accumulated other comprehensive income (loss)	(4,891)	—
Total partners' capital	283,959	149,984
Total liabilities and partners' capital	$ 657,879	$ 284,435

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2005	2004	2003
Cash flows from operating activities			
Net income	$ 51,161	$ 34,315	$ 22,690
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	30,628	18,632	16,578
Unrealized loss on derivatives	14,024	—	—
Noncash interest expense	1,735	1,678	520
Equity earnings, net of distributions	1,269	561	—
Cumulative effect of change in accounting principle	—	—	107
Changes in operating assets and liabilities:			
Accounts receivable	(27,318)	(1,759)	(2,495)
Inventory	755	—	—
Accounts payable	18,090	81	140
Accrued liabilities	6,490	33	1,456
Deferred income	2,063	2,295	2,321
Derivative assets and liabilities	(6,588)	—	—
Other assets and liabilities	1,403	(1,054)	(240)
Net cash provided by operating activities	93,712	54,782	41,077
Cash flows from investing activities			
Acquisitions, net of cash acquired	(290,938)	(28,675)	(1,361)
Additions to property, plant and equipment	(12,735)	(855)	(3,930)
Other	52	1,104	580
Net cash used in investing activities	(303,621)	(28,426)	(4,711)
Cash flows from financing activities			
Payments for debt issuance costs	(2,385)	(1,234)	(2,142)
Proceeds from borrowings	288,800	28,500	90,000
Repayments of borrowings	(151,600)	(2,500)	(88,387)
Proceeds from issuance of partners’ capital	129,239	—	317
Distributions to partners	(51,949)	(39,191)	(36,708)
Net cash provided by (used in) financing activities	212,105	(14,425)	(36,920)
Net increase (decrease) in cash and cash equivalents	2,196	11,931	(554)
Cash and cash equivalents—beginning of period	20,997	9,066	9,620
Cash and cash equivalents—end of period	$ 23,193	$ 20,997	$ 9,066
Supplemental disclosures			
Cash paid for interest	$ 12,138	$ 5,472	$ 3,248
Noncash investing and financing activities			
Issuance of partners’ capital for acquisitions	$ 10,415	$ 1,060	$ 4,969
Assumption of liabilities in acquisitions	$ 3,981	$ —	$ 198

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL AND COMPREHENSIVE INCOME
(in thousands)

	Common Units		Class B Common Units		Subordinated Units		General Partner	Accumulated Other Comprehensive Income (Loss)	Total	Comprehensive Income (Loss)
	Units	Amount	Units	Amount	Units	Amount				
Balance at December 31, 2002	9,172	$ 154,033	947	$ 19,610	7,650	$ (11,776)	$ 665	$ —	$ 162,532	
Capital contributions	—	—	—	—	—	—	6	—	6	
Issuance of units	13	311	241	4,969	—	—	—	—	5,280	
Conversion of Class B units to common units	1,188	24,579	(1,188)	(24,579)	—	—	—	—	—	
Distributions ($2.06 per unit)	—	(19,496)	—	(702)	—	(15,760)	(750)	—	(36,708)	
Net income allocation	—	12,058	—	702	—	9,476	454	—	22,690	$ 22,690
Balance at December 31, 2003	10,373	171,485	—	—	7,650	(18,060)	375	—	153,800	$ 22,690
Issuance of units	51	1,060	—	—	—	—	—	—	1,060	
Conversion of subordinated units	1,913	(5,483)	—	—	(1,913)	5,483	—	—	—	
Distributions ($2.12 per unit)	—	(22,190)	—	—	—	(16,218)	(783)	—	(39,191)	
Net income allocation	—	19,866	—	—	—	13,763	686	—	34,315	$ 34,315
Balance at December 31, 2004	12,337	164,738	—	—	5,737	(15,032)	278	—	149,984	$ 34,315
Capital contributions	—	—	—	—	—	—	2,783	—	2,783	
Issuance of units	2,748	136,871	—	—	—	—	—	—	136,871	
Conversion of subordinated units	1,912	(5,538)	—	—	(1,912)	5,538	—	—	—	
Distributions ($2.48 per unit)	—	(35,775)	—	—	—	(14,243)	(1,931)	—	(51,949)	
Net income allocation	—	35,742	—	—	—	13,297	2,122	—	51,161	$ 51,161
Other comprehensive loss	—	—	—	—	—	—	—	(4,891)	(4,891)	(4,891)
Balance at December 31, 2005	16,997	$ 296,038	—	$ —	3,825	$ (10,440)	$ 3,252	$ (4,891)	$ 283,959	$ 46,270

See accompanying notes to consolidated financial statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Penn Virginia Resource Partners, L.P. (the "Partnership," "we," "us" or "our"), is a Delaware limited partnership formed by Penn Virginia Corporation ("Penn Virginia") in 2001 primarily to engage in the business of managing coal properties in the United States. Since the acquisition of a natural gas midstream business in March 2005, we conduct operations in two business segments: coal and natural gas midstream.

In our coal segment, we do not operate any mines. Instead, we enter into leases with various third-party operators which give those operators the right to mine coal reserves on our land in exchange for royalty payments. We also provide fee-based infrastructure facilities to some of our 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. We also sell timber growing on our land.

We purchased our midstream business on March 3, 2005, through the acquisition of Cantera Gas Resources, LLC (see Note 3). As a result of this acquisition, we own and operate a significant set of midstream assets. Our 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 general partner of the Partnership is Penn Virginia Resource GP, LLC, a wholly owned subsidiary of Penn Virginia.

2. Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Partnership and all wholly-owned subsidiaries. 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.

Property, Plant and Equipment

Property, plant and equipment consist of our ownership in coal fee mineral interests, our royalty interest in oil and natural gas wells, processing facilities, gathering systems, compressor stations and related equipment. Property, plant 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, plant 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, we carry out core-hole drilling activities on our 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. We deplete oil and gas properties on a unit-of-production basis over the remaining life of the reserves. 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.

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 10, "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 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 the date of adoption. The determination of fair value was based upon regional market and facility type information. In conjunction with the initial application of SFAS No. 143, we recorded a cumulative effect of change in accounting principle of $0.1 million as a decrease 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.

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. An impairment loss must be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we would recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the present value of future net cash flows from proved reserves, discounted utilizing a rate commensurate with the risk and remaining lives of the assets.

Equity Investments

We use the equity method of accounting to account for our investment in a coal handling joint venture, recording our initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect our share of income of the investee and is reduced to reflect our share of losses of the investee or distributions received from the investee as the joint venture reports them. Our share of earnings or losses from the investment is included in coal services revenues in the consolidated statements of income. Coal services revenues also includes amortization of the amount of our equity investment that exceeds our portion of the underlying equity in net assets. We record amortization over the life of coal services contracts in place at the time of our initial investment.

Goodwill

We had approximately $7.7 million of goodwill at December 31, 2005, based upon the preliminary purchase price allocation for the Cantera Acquisition (as defined in Note 3). This amount may change based upon the final purchase price allocation. The goodwill has been allocated to the natural gas 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 3) and the Alloy Acquisition (see Note 4) and $4.6 million for rights-of-way acquired in the Cantera Acquisition (see Note 3). These amounts may change based on the final Cantera Acquisition purchase price allocation as described in Note 3. 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. Total intangible amortization was approximately $4.2 million in 2005. There were no intangible assets or related amortization in 2004. As of December 31, 2005, accumulated amortization of intangible assets was $4.2 million.

Aggregate amortization expense for the year ended December 31, 2005, was approximately $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

Debt Issuance Costs

Debt issuance costs relating to long-term debt have been capitalized and are being amortized over the term of the related debt instrument.

Long-Term Prepaid Minimums

We lease a portion of our reserves from third parties which require monthly or annual minimum rental payments. The prepaid minimums are recoupable from future production and are deferred and charged to royalty expense as the coal is subsequently produced. We evaluate the recoverability of the prepaid minimums on a periodic basis; consequently, any prepaid minimums that cannot be recouped are charged to royalty expense.

Environmental Liabilities

Other liabilities include accruals for environmental liabilities that we either assumed in connection with certain acquisitions or recorded in operating expenses when it became probable that a liability had been incurred and the amount of that liability could be reasonably estimated.

Concentration of Credit Risk

Approximately 84 percent of our accounts receivable at December 31, 2005, resulted from natural gas midstream customers and approximately 16 percent resulted from accrued revenues from coal lessee production. Approximately 37 percent of total accounts receivable at December 31, 2005, related to three midstream customers. These concentrations 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 lessee or customer, 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 fixed rate long-term debt, approximate fair value. The fair value of fixed rate long-term debt at December 31, 2005 and 2004, was $81.2 million and $86.2 million.

Revenues

Natural Gas Midstream Revenues. Revenues from the sale of natural gas liquids ("NGLs") and residue gas are recognized when we sell the NGLs and residue gas produced at our 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 our lessees and the corresponding revenues from those sales. Most of our coal leases are based on minimum monthly or annual payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price. The remainder of our 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 our best estimates of coal mined on our properties.

Coal Services. Coal services revenues are recognized when lessees use our facilities for the processing, loading and/or transportation of coal. Coal services revenues consist of fees collected from lessees for the use of our loadout facility, coal preparation plants and dock loading facility. We also include equity earnings in coal services revenues. We recognize our share of income or losses from our investment in a coal handling joint venture as the joint venture reports them to us.

Minimum Rentals. Most of our lessees must make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalty revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the 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 NGL, crude oil and natural gas price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of 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 the board of directors of our general partner.

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 midstream revenues or cost of gas purchased in the period that the related production is delivered.

Income Taxes

Subsequent to our formation, no provision for income taxes related to the operations of the Partnership has been included in the accompanying financial statements because, as a partnership, we are not subject to federal or state income taxes and the tax effect of our activities accrues to the unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under our partnership agreement.

Net Income per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined by dividing net income, after deducting our general partner's two percent interest and incentive distribution rights, by the weighted average number of outstanding common units and subordinated units. At December 31, 2005, there were no dilutive units.

New Accounting Standards

In March 2005, the Financial Accounting Standards Board (the "FASB") released Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"), which provides guidance for applying SFAS No. 143, *Accounting for Asset Retirement Obligations.* 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 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 do not expect the adoption of the provisions of SFAS No. 154 to have a material impact on our consolidated financial statements.

3. Acquisition of Natural Gas Midstream Business

On March 3, 2005, we completed our 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, we own and operate a significant set of midstream assets including gas gathering pipelines and three natural gas processing facilities. Our 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 we funded with a $110 million term loan and with long-term debt under our 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. We used proceeds of $126.4 million from our sale of common units in a subsequent public offering in March 2005 and a $2.6 million contribution from our general partner to repay our term loan in full and to reduce outstanding indebtedness under our 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 our entry into the natural gas midstream business and our 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, 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 the consolidated results of operations of the Partnership as if the Cantera Acquisition and related 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, interest expense for acquisition debt and the change in weighted average common units resulting from the public offering. 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.

	Year Ended December 31,	
	2005	**2004**
	(in thousands, except share data)	
Revenues	$ 518,790	$ 361,162
Net income	$ 51,519	$ 45,521
Net income per limited partner unit, basic and diluted	$ 2.43	$ 2.17

4. Other Acquisitions

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

In March 2005, we 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 our revolving credit facility. The coal reserves are predominantly low sulfur and high BTU content, and development will occur in conjunction with our 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 of net proved oil and gas reserves.

In April 2005, we 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 our property commenced production. The seller remained on the property as the lessee and operator. The Alloy Acquisition was funded with long-term debt under our revolving credit facility.

In July 2005, we 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 our issuance to the seller of approximately 209,000 common units. In addition, we assumed $0.7 million of liabilities related to the acquired property.

In July 2005, we 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 we assumed $3.3 million of deferred income. This coal reserve acquisition is our first in the Illinois Basin and was funded with long-term debt under our 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, we 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 our 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, we 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 our 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 we 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 the lessees.

5. Property and Equipment

Property and equipment includes:

	December 31, 2005	December 31, 2004
	(in thousands)	
Coal properties	$ 340,439	$ 251,244
Compressor stations	45,405	—
Gathering systems	91,216	—
Coal services equipment	23,351	17,442
Processing plants	14,533	—
Land	10,675	1,797
Oil and gas properties	5,324	—
Other property and equipment	4,097	1,063
	535,040	271,546
Accumulated depreciation, depletion and amortization	(76,258)	(49,931)
Net property and equipment	$ 458,782	$ 221,615

6. Equity Investments

As described in Note 4, “Other Acquisitions,” we acquired a 50 percent interest in Coal Handling Solutions, LLC, a joint venture formed to own and operate end-user coal handling facilities. We account 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, our equity investment totaled $26.6 million, which exceeded our 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, we recognized equity earnings of $1.1 million in 2005 and $0.4 million in 2004 with a corresponding increase in the investment. Cash distributions of approximately $2.3 million and $1.0 million received from the joint venture in 2005 and 2004 reduced the investment. Equity earnings are included in coal services revenues on the consolidated statements of income.

7. Allowance for Prepaid Minimums

We establish provisions for losses on long-term prepaid minimums if we determine that we will not recoup all or part of the outstanding balance. Collectibility is reviewed periodically and an allowance is established or adjusted, as necessary, using the specific identification method. The allowance is netted against long-term prepaid minimums on the accompanying consolidated balance sheet. The following table presents the activity of our allowance for prepaid minimums for each of the last three years:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Balance at beginning of period	$ 1,514	$ 1,334	$ 1,240
Charges to expense	178	180	94
Balance at end of period	$ 1,692	$ 1,514	$ 1,334

8. Hedging Activities

Commodity Cash Flow Hedges

Natural Gas Midstream Segment. When we agreed to acquire Cantera, we 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, we formally designated the agreements as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* 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 us to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and we are 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 we will receive a correspondingly higher or lower amount for the physical sale of the commodity over the same period. In addition, we 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 our derivative agreements are determined based on forward price quotes for the respective commodities as of December 31, 2005. The following table sets forth our 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, we 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 $6.1 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, we 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, we expect to realize $10.1 million of hedging losses within the next 12 months. The amounts that we 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, we had no monthly settlements and recognized no net hedging losses in natural gas midstream revenues in 2004.

In November 2005, we 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, we 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 our senior unsecured notes (see Note 11) in March 2003, we 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 us to the counterparty in July 2005. Upon settlement of the Senior Notes Swap agreement, the $0.8 million negative fair value adjustments of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the Notes (as defined in Note 11) using the effective interest rate method.

In September 2005, we entered into interest rate swap agreements to establish fixed rates on $60 million of the LIBOR-based portion of the outstanding balance on our revolving credit facility (see Note 11) until March 2010 (the "Revolver Swaps"). We pay 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, we reported (i) a derivative asset of approximately $1.2 million and (ii) a gain in accumulated other comprehensive income of $1.2 million related to the interest rate swap. In connection with periodic settlements, we 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, we expect to realize $0.3 million of hedging gains within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of open derivative agreements prior to settlement.

9. Accrued Liabilities

Accrued liabilities include:

	December 31,	
	2005	2004
	(in thousands)	
Accrued interest	$ 1,680	$ 1,499
Accrued property taxes	1,565	650
Accrued severance taxes	1,255	—
Accrued royalty expense	348	296
Pipeline imbalance	2,504	—
Other	2,436	498
Total accrued liabilities	$ 9,788	$ 2,943

10. 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 on the accompanying consolidated balance sheets:

	Year Ended December 31,	
	2005	2004
	(in thousands)	
Balance at beginning of period	$ 723	$ 666
Adoption of FIN 47	635	—
Accretion expense	100	57
Balance at end of period	$ 1,458	$ 723

11. Long-Term Debt

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

	December 31,	
	2005	2004
	(in thousands)	
Revolving credit facility—variable rate of 5.7 percent at December 31, 2005	$ 172,000	$ 30,000
Senior unsecured notes (1)	82,954	87,726
	254,954	117,726
Less: Current maturities	(8,108)	(4,800)
Total long-term debt	$ 246,846	$ 112,926

(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 8).

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 “Revolver”) that matures in March 2010 and a $110 million term loan. A portion of the Revolver and the term loan were used to fund the Cantera Acquisition and to repay borrowings under our previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million common units in March 2005 and a $2.6 million contribution from our general partner were used to repay the $110 million term loan and a portion of the amount outstanding under the Revolver. The term loan cannot be re-borrowed. The 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. We had outstanding letters of credit of $1.6 million as of December 31, 2005 and 2004. In 2005, we incurred commitment fees of $0.4 million on the unused portion of the Revolver.

In July 2005, we amended the credit agreement to increase the size of the commitment under the Revolver from $150 million to $300 million and to increase our one-time option (upon receipt by the credit facility's administrative agent of commitments from one or more lenders) to expand the 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 our ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if we select 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 we select the LIBOR-based borrowing option. The other terms of the credit agreement remained unchanged. The financial covenants of the Revolver require us to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted our additional borrowing capacity under the Revolver to approximately $106.5 million at December 31, 2005. As of December 31, 2005, we were in compliance with all of our covenants under the Revolver.

In September 2005, we 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 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 8).

Prior to the Cantera Acquisition, we 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 our 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 our 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. We paid commitment fees on the unused portion of the revolving credit facility.

In connection with the Cantera Acquisition, during the fourth quarter of 2004, we entered into a bridge loan commitment with two financial institutions. The bridge loan was terminated late in the fourth quarter of 2004, and we replaced it with the expanded credit facility as described above. In the fourth quarter of 2004, we paid loan issue costs of approximately $1.2 million related to the bridge loan commitment, which were recorded as interest expense in 2004.

Senior Unsecured Notes

In March 2003, we closed a private placement of $90 million of senior unsecured notes (the "Notes"). The 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 Notes contain various covenants similar to those contained in the Revolver. The Notes have an equal priority of payment as all other unsecured indebtedness, including the Revolver. As of December 31, 2005, we were in compliance with all of our covenants under the Notes.

In conjunction with the closing of the Cantera Acquisition, we amended the Notes to allow us 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, we agreed to a 0.25 percent increase in the fixed interest rate on the Notes, from 5.77 percent to 6.02 percent. The amendment to the Notes also requires that we obtain an annual confirmation of our credit rating, with a 1.00 percent increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. On March 15, 2005, our investment grade credit rating was confirmed by Dominion Bond Rating Services.

Upon settlement of the Senior Notes Swap agreement (see Note 8), 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 Notes using the interest rate method.

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	185,400
Thereafter	24,200
Total principal	255,700
Less: Terminated interest rate swap	(746)
Total debt, including current maturities	$ 254,954

12. Partnership Capital and Distributions

As of December 31, 2005, partners' capital consisted of 17.0 million common units, representing an 80 percent limited partner interest, 3.8 million subordinated units, representing an 18 percent limited partner interest, and a two percent general partner interest. As of December 31, 2005, affiliates of Penn Virginia, in the aggregate, owned a 39 percent interest in the Partnership, consisting of 3.9 million common units, 3.8 million subordinated units and a two percent general partner interest.

Net income per limited partner unit is based on the weighted average number of common and subordinated units outstanding during the period and is allocated in the same ratio as quarterly cash distributions are made. Net income per limited partner unit is computed by dividing the limited partners' interest in net income, after deducting the general partner's two percent interest and incentive distributions, by the weighted average number of limited partner units outstanding.

We distribute 100 percent of Available Cash (as defined in our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available Cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Our general partner has the discretion to establish cash reserves that are necessary or appropriate to (i) provide for the proper conduct of our business; (ii) comply with applicable law, any of our debt instruments or other agreements; or (iii) provide funds for distributions to unitholders and our general partner for any one or more of the next four quarters.

Cash Distributions

Distributions of Available Cash to holders of subordinated units are subject to the prior rights of holders of common units to receive the minimum quarterly distribution ("MQD") for each quarter during the subordinated period and to receive any arrearages in the distribution of the MQD on the common units for the prior quarters during the subordination period. The MQD is $0.50 per unit ($2.00 per unit on an annual basis). We expect to make quarterly distributions of $0.50 or more per common unit to the extent we have sufficient cash from our operations after payment of fees and expenses. According to our partnership agreement, our general partner receives incremental incentive cash distributions if cash distributions exceed certain target thresholds as follows:

	Unitholders	General Partner
Quarterly cash distribution per unit:		
First target – up to $0.55 per unit	98%	2%
Second target – above $0.55 per unit up to $0.65 per unit	85%	15%
Third target – above $0.65 per unit up to $0.75 per unit	75%	25%
Thereafter – above $0.75 per unit	50%	50%

For the years ended December 31, 2005, 2004 and 2003, we declared and paid distributions of $2.48, $2.12 and $2.06 per unit to the unitholders. On February 14, 2006, the board of directors of our general partner paid a $0.70 per unit quarterly distribution ($2.80 per unit on an annual basis) to unitholders of record on February 3, 2006.

Subordination Period

During the subordination period, the common units will have the right to receive the MQD, plus arrearages, before we make any distributions on the subordinated units. The subordination period will end once we meet certain tests regarding the payments of distributions as defined in the partnership agreement, but it generally cannot end before September 30, 2006. When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis and the common units will no longer be entitled to arrearages.

Before the end of the subordination period, 50 percent of the subordinated units, or up to 3,824,940 subordinated units, converted into common units on a one-for-one basis immediately after the distribution of available cash to partners as follows:

- For the quarter ended September 30, 2004, 25 percent of the subordinated units converted to common units on November 12, 2004; and
- For the quarter ended September 30, 2005, 25 percent of the subordinated units converted to common units on November 14, 2005.

The early conversions occurred because, at the end of the applicable quarter each of the following three tests are met:

- distributions of available cash from operating surplus on each common and subordinated unit 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.

Limited Call Right

If at any time persons other than our general partner and its affiliates do not own more than 20 percent of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then current market price of the common units. If quarterly distributions of Available Cash exceed the MQD or certain target distribution levels, our general partner will receive distributions, which are generally equal to 15 percent, then 25 percent and then 50 percent of the distributions of Available Cash that exceed the target distribution levels.

13. Related Party Transactions

General and Administrative

Penn Virginia charges us for certain corporate administrative expenses which are allocable to its subsidiaries. When allocating general corporate expenses, consideration is given to property and equipment, payroll and general corporate overhead. Any direct costs are paid by us. Total corporate administrative expenses charged to us totaled $2.6 million, $1.5 million and $1.1 million for the years ended December 31, 2005, 2004 and 2003. These costs are reflected in general and administrative expenses in the accompanying consolidated statements of income. At least annually, management performs an analysis of general corporate expenses based on time allocations of shared employees and other pertinent factors. Based on this analysis, management believes the allocation methodologies used are reasonable.

Accounts Payable—Affiliate

Amounts payable to related parties totaled $2.8 million and $1.0 million as of December 31, 2005 and 2004. This balance consists primarily of amounts due to our general partner for general and administrative expenses incurred on our behalf and is included in accounts payable on the accompanying consolidated balance sheets.

14. Long-Term Incentive Plan

Our general partner 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 our general partner and employees of our general partner's affiliates who perform services for us. 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 our general partner's board of directors. 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

Our general partner granted 438 common units at a weighted average grant-date fair value of $50.71 per unit to non-employee directors in 2005. Our 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. Our 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 our outstanding subordinated units. In addition, all restricted units will vest upon a change of control of our general partner or Penn Virginia. If a grantee's employment with, or membership on the board of directors of, our 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 our general partner and made subject to a risk of forfeiture during the applicable restriction period.

Our general partner granted 25,488 restricted units at a weighted average grant-date fair value of $50.76 per unit to officers and employees of our general partner in 2005. Our 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 our general partner in 2004. Our 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 our 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 our general partner 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 our general partner. Common units delivered in connection with deferred common units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner is entitled to reimbursement by us for the cost incurred in acquiring common units. Deferred common units awarded to directors receive all cash or other distributions paid by us on account of our common units. Our general partner 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.

15. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2005, 2004 and 2003, was $0.9 million, $0.2 million and $0.2 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):

Year ending December 31,	
2006	$ 934
2007	869
2008	760
2009	598
2010	590
Total minimum payments	$ 3,751

Rental commitments primarily relate to equipment, car, building and land leases. Also included are rental commitments primarily related to coal reserve-based properties which we sublease, or intend 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 we will incur approximately $0.6 million in rental commitments annually until the reserves have been exhausted.

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 our financial position, liquidity or operations.

Environmental Compliance

The operations of our coal lessees and our 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 our 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 us against any and all future environmental liabilities. We regularly visit coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of our coal lessees and our natural gas midstream segment comply with existing regulations and does not expect any material impact on our financial condition or results of operations.

As of December 31, 2005 and 2004, environmental liabilities included $2.5 million and $1.5 million, representing our best estimate of our liabilities as of those dates related to our coal and natural gas midstream businesses. We have 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. The environmental liabilities are not covered by our indemnification agreement with Penn Virginia.

Mine Health and Safety Laws

There are numerous mine health and safety laws and regulations applicable to the coal mining industry. However, since we do not operate any mines and do not employ any coal miners, we are not subject to such laws and regulations. Accordingly, we have not accrued any related liabilities.

16. Comprehensive Income

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

	Year Ended December 31,		
	2005	2004	2003
Net income	$ 51,161	$ 34,315	$ 22,690
Unrealized holding gains (losses) on hedging activities	(3,903)	—	—
Reclassification adjustment for hedging activities	(988)	—	—
Comprehensive income	$ 46,270	$ 34,315	$ 22,690

17. 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 the Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our coal operations and our natural gas midstream operations. Accordingly, our reportable segments are as follows:

Coal

The coal segment includes:

- management of coal properties located in the Appalachian and Illinois Basin regions of the United States and in New Mexico;
- other land management activities such as selling standing timber and real estate rentals;
- fee-based infrastructure facilities leased to certain lessees; and
- our investment in a joint venture which primarily provides coal handling facilities to end-user industrial plants.

Natural Gas Midstream

The natural gas 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.

In 2004, we reported two segments – coal royalty and coal services. As a result of the Cantera Acquisition, our Chief Executive Officer and other chief operating decision makers now review the operating results of our coal business on an aggregated basis. Accordingly, we now report the coal and natural gas midstream businesses as our two segments. 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):

	Coal	Natural Gas Midstream (4)	Total
		(in thousands)	
For the year ended December 31, 2005			
Revenues	$ 95,755	$ 350,593	$ 446,348
Operating costs and expenses	16,121	321,509	337,630
Depreciation, depletion and amortization	17,890	12,738	30,628
Operating income	$ 61,744	$ 16,346	$ 78,090
Interest expense			(14,054)
Interest income			1,149
Unrealized loss on derivatives			(14,024)
Net income			$ 51,161
Total assets	$ 372,322	$ 285,557	$ 657,879
Equity investments	26,612	60	26,672
Additions to property, plant and equipment and acquisitions, net of cash acquired (1)	112,497	206,811	319,308
For the year ended December 31, 2004			
Revenues	$ 75,630	$ —	$ 75,630
Operating costs and expenses	16,479	—	16,479
Depreciation, depletion and amortization	18,632	—	18,632
Operating income	$ 40,519	$ —	$ 40,519
Interest expense			(7,267)
Interest income			1,063
Net income			$ 34,315
Total assets	$ 284,435	$ —	$ 284,435
Equity investments	27,881	—	27,881
Additions to property, plant and equipment and acquisitions, net of cash acquired (2)	2,148	—	2,148
For the year ended December 31, 2003			
Revenues	$ 55,642	$ —	$ 55,642
Operating costs and expenses	12,504	—	12,504
Depreciation, depletion and amortization	16,578	—	16,578
Operating income	$ 26,560	$ —	$ 26,560
Interest expense			(4,986)
Interest income			1,223
Cumulative effect of change in accounting principle			(107)
Net income			$ 22,690
Total assets	$ 259,892	$ —	$ 259,892
Additions to property, plant and equipment and acquisitions, net of cash acquired (3)	10,458	—	10,458

(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) Includes noncash expenditures of $1.1 million.
(3) 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 is equal to total revenues less operating costs and expenses and depreciation, depletion and amortization. Operating income does not include certain other income items, interest expense, interest income and income taxes. Identifiable assets are those assets used in our operations in each segment.

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 18 percent and 17 percent, of our consolidated net revenues.

18. Quarterly Financial Information (Unaudited)

Summarized Quarterly Financial Data

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2005 (1)	(in thousands, except share data)			
Revenues	$ 46,190	$ 109,609	$ 128,405	$ 162,144
Operating income	$ 14,300	$ 20,436	$ 22,496	$ 20,858
Net income (loss) (2)	$ (2,471)	$ 16,865	$ 22,370	$ 14,397
Basic and diluted net income (loss) per limited partner unit, common and subordinated (2) (3)	$ (0.13)	$ 0.79	$ 1.03	$ 0.69
Weighted average number of units outstanding, basic and diluted:				
Common	12,618	14,867	15,085	16,360
Subordinated	5,737	5,737	5,737	4,462
2004				
Revenues	$ 17,963	$ 18,732	$ 19,397	$ 19,538
Operating income	$ 9,188	$ 9,616	$ 10,540	$ 11,175
Net income	$ 8,127	$ 8,469	$ 9,147	$ 8,572
Basic and diluted net income per limited partner unit, common and subordinated (3)	$ 0.44	$ 0.46	$ 0.50	$ 0.46
Weighted average number of units outstanding, basic and diluted:				
Common	10,407	10,425	10,425	11,700
Subordinated	7,650	7,650	7,650	6,375

(1) Includes the results of operations from the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) First quarter 2005 includes a $13.9 million unrealized loss on derivatives for mark-to-market adjustments on certain derivative agreements before the agreements qualified for hedge accounting.
(3) The sum of the quarters may not equal the total of the respective year's net income per limited partner unit due to changes in the weighted average units outstanding throughout the year.

19. Subsequent Event

On February 23, 2006, the board of directors of our general partner declared a two-for-one split of our common and subordinated units. To effect the split, we will distribute one additional common unit and one additional subordinated unit (a total of 16,997,325 common units and 3,824,940 subordinated units) on April 4, 2006, for each common unit and subordinated unit, respectively, held of record at the close of business on March 28, 2006.

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 37 percent of our total assets, as of December 31, 2005, and PVR Midstream LLC's total revenues were $350.6 million, or approximately 79 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 ("KPMG"), 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 our General Partner*

As is commonly the case with publicly traded limited partnerships, we do not employ any of the persons responsible for managing or operating our business, but instead we reimburse our general partner for its services. The following table sets forth information concerning the directors and executive officers of our general partner. All directors of our general partner are elected, and may be removed, by Penn Virginia Resource GP Corp., its sole member and a wholly owned subsidiary of Penn Virginia.

Name	Age	Position with our General Partner
A. James Dearlove	58	Chairman of the Board of Directors and Chief Executive Officer
Edward B. Cloues, II	58	Director
John P. DesBarres	66	Director
James L. Gardner	54	Director
Keith B. Jarrett	57	Director
James R. Montague	58	Director
Marsha R. Perelman	51	Director
Frank A. Pici	50	Director and Vice President and Chief Financial Officer
Nancy M. Snyder	53	Director and Vice President and General Counsel
Keith D. Horton	52	President and Chief Operating Officer
Ronald K. Page	55	Vice President, Corporate Development

A. James Dearlove has served as Chairman of the Board of Directors and Chief Executive Officer of our general partner since December 2002 and July 2001. Mr. Dearlove has also served in various capacities with Penn Virginia since 1977, including as President and Chief Executive Officer since May 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 also serves as a director of Penn Virginia and as a director of the National Council of Coal Lessors.

Edward B. Cloues, II has served as a director of our general partner since January 2003. Since January 1998, Mr. Cloues has served as Chairman of the Board and Chief Executive Officer of K-Tron International, Inc., a provider of material handling equipment and systems. From October 1979 to January 1998, Mr. Cloues was a partner of Morgan, Lewis & Bockius LLP, an international law firm. Mr. Cloues also serves as a director of Penn Virginia and is the non-executive Chairman of the Board of AMREP Corporation.

John P. DesBarres has served as a director of our general partner since July 2001. Mr. DesBarres is currently a private investor residing in Park City, Utah. From 1991 to 1995, Mr. DesBarres served as the Chairman, President and Chief Executive Officer of Transco Energy Company, an energy company which merged with The Williams Companies, Inc. in 1995. Mr. DesBarres serves as a director of American Electric Power, Inc. and as a director of the general partner of Magellan Midstream Partners, L.P.

James L. Gardner has served as a director of our general partner since January 2006. Since 2005, Mr. Gardner has been an Associate Professor of Interdisciplinary Studies at Freed-Hardeman University. From 2002 to 2004, Mr. Gardner served as Executive Vice President and Chief Administrative Officer of Massey Energy Corporation ("Massey"), a coal mining company. From 2000 to 2002, Mr. Gardner was in the private practice of law, principally representing Massey. From 1993 to 2000, Mr. Gardner served in various capacities with Massey, including as Senior Vice President and General Counsel from 1994 to 2000 and as General Counsel from 1993 to 1994. From 1991 to 1993, Mr. Gardner was an attorney at the law firm of Hunton & Williams LLP.

Keith B. Jarrett has served as a director of our general partner since December 2001. Since January 2002, Mr. Jarrett has been an investor and advisor to venture-stage companies in the investment technology space. Prior to January 2002, Mr. Jarrett served in various capacities with affiliates of The Thomson Corporation, a public company listed on the New York, Toronto and London Stock Exchanges. Mr. Jarrett served as President and Chief Executive Officer of Thomson Financial Ventures from 1998 to December 2001 and as President and Chief Executive Officer of Thomson Financial International from 1994 to June 2000. The Thomson Financial companies are in the business of selling information and technology solutions to the global banking and securities management industries.

James R. Montague has served as a director of our general partner since July 2001. From 2001 to 2002, Mr. Montague served as President of EnCana Gulf of Mexico LLC, a subsidiary of EnCana Corporation, which is in the business of oil and gas exploration and production. From 1996 to June 2001, Mr. Montague served as President of two subsidiaries of International Paper Company, IP Petroleum Company, an exploration and production oil and gas company, and GCO Minerals Company, a company that manages International Paper Company's mineral holdings. Mr. Montague also serves as Chairman of the Board of Memorial Hermann Healthcare System. Mr. Montague serves as a director of The Meridian Resource Corporation and as a director of the general partner of Magellan Midstream Partners, L.P.

Marsha R. Perelman has served as a director of our general partner since May 2005. In 1993, Ms. Perelman founded, and since then has been the Chief Executive Officer of, Woodforde Management, Inc., a holding company. In 1983, she co-founded, and from 1983 to 1990 served as the President of, Clearfield Ohio Holdings, Inc., a gas gathering and distribution company. In 1983, she also co-founded, and from 1983 to 1990 served as Vice President of, Clearfield Energy, Inc., a crude oil gathering and distribution company. From 1980 to 1983, she served as Vice President, Penn Central Energy Group, of the Penn Central Corporation, an oil field services company. Ms. Perelman also serves as a director of Penn Virginia.

Keith D. Horton has served as President and Chief Operating Officer of our general partner since July 2001 and as President of the Operating Company since September 2001. Mr. Horton has also served in various capacities with Penn Virginia since 1981, including as Executive Vice President since December 2000, Vice President—Eastern Operations from February 1999 to December 2000 and Vice President from February 1996 to February 1999. Mr. Horton also serves as a director of Penn Virginia and as director or the Virginia Mining Association, the Powell River Project and the Eastern Coal Council.

Nancy M. Snyder has served as Vice President and General Counsel and as a director of our general partner since July 2001. Ms. Snyder has also served in various capacities with Penn Virginia 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. 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.

Frank A. Pici has served as Vice President and Chief Financial Officer of our general partner since September 2001 and as a director since October 2002. Mr. Pici has also served as Executive Vice President and Chief Financial Officer of Penn Virginia since September 2001. From 1996 to 2001, Mr. Pici served as Vice President—Finance and Chief Financial Officer of Mariner Energy, Inc. ("Mariner"), a Houston, Texas-based 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 positions at Cabot Oil & Gas Company, including as 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.

Ronald K. Page has served as Vice President, Corporate Development for our general partner since July 2003 and as President of PVR Midstream LLC since January 2005. Mr. Page has also served in various capacities with Penn Virginia since July 2003, including as Vice President since May 2005 and as Vice President, Corporate Development from July 2003 to May 2005. From January 1998 to May 2003, Mr. Page served in various positions with El Paso Field Services Company, including Vice President of Commercial Operations—Texas Pipelines and Processing, Vice President of Business Development and Director of Business Development. From October 1995 to 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 Vice President of Operations at Seagull's Enstar Natural Gas Company, Vice President of Pipelines and Marketing and Manager of Engineering.

Information About the Board of Directors and the Committees of our General Partner

Messrs. Cloues, DesBarres, Gardner, Jarrett and Montague and Ms. Perelman are "independent directors," as defined by New York Stock Exchange Listing Standards and SEC rules and regulations ("Independent Directors"). The board of directors of our general partner has determined that none of the Independent Directors have any relationship with us other than as a director of our general partner or its affiliate, Penn Virginia.

Our general partner's Independent Directors meet during regularly scheduled executive sessions without management as well as during meetings which are scheduled on an as needed basis. John P. DesBarres, an Independent Director, presides over executive sessions. Unitholders and other interested parties may communicate any concerns they have regarding us by contacting Mr. DesBarres in writing c/o Secretary, Penn Virginia Resource GP, LLC, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087.

The Audit Committee. Messrs. DesBarres, Jarrett and Montague are the members of the audit committee of our general partner, and each such member is an Independent Director. John P. DesBarres is an audit committee financial expert as defined by Section 407 of the Sarbanes Oxley Act of 2002. The audit committee of our general partner is responsible for the appointment, compensation, evaluation and termination of our independent registered public accountants, and oversees the work, internal quality-control procedures and independence of the independent registered public accountants. The committee discusses with management and the independent registered public accountants our annual audited and quarterly unaudited financial statements and recommends to the board of directors of our general partner that our annual audited financial statements be included in our Annual Report on Form 10-K. The committee also meets and discusses with management earnings press releases and guidance provided to analysts. The committee also provides oversight with respect to business risk matters, compliance with ethics policies and our compliance with legal and regulatory requirements. The committee has established procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, auditing and other matters and the confidential anonymous submission by employees of concerns regarding questionable accounting, auditing and other matters. The committee obtains advice and assistance from outside legal, accounting or other advisors as it deems necessary to carry out its duties.

The Conflicts Committee. The conflicts committee of our general partner reviews transactions between us and Penn Virginia, or any of its affiliates, and any other transactions involving us or our affiliates that our board of directors believes may involve conflicts of interest. The conflicts committee then determines whether such transactions are fair and reasonable to us, and whether our general partner has upheld the fiduciary or other duties it owes to us. The committee may obtain advice and assistance from outside legal, financial or other advisors as it deems necessary to carry out its duties.

The Compensation and Benefits Committee. The compensation and benefits committee of our general partner reviews and approves corporate goals and other objectives regarding our chief executive officer's compensation and evaluates our chief executive officer's performance in light of those goals, objectives and other relevant factors together with the compensation and benefits committee of Penn Virginia. The committee assists the Penn Virginia compensation and benefits committee when it sets the short and long-term compensation for our chief executive officer's and other executive officers of the our general partner. The committee also periodically reviews and makes recommendations or decisions regarding our general partner's incentive compensation and equity-based plans, provides oversight with respect to our general partner's other employee benefit plans and reports its recommendations to our board of directors. The committee reviews and makes recommendations to our board of directors regarding director compensation policy. The committee may obtain advice and assistance from outside compensation consultants or other advisors as it deems necessary to carry out its duties.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires officers and directors of our general partner and beneficial owners more than ten percent of our common units to file, by a specified date, reports of beneficial ownership and changes in beneficial ownership with the SEC and to furnish copies of such reports to us. We believe that all such filings were made on a timely basis in 2005 with the exception of one Form 4 which was inadvertently filed five days late by us on behalf of John P. DesBarres reporting the award of 38 deferred common units.

Item 11   *Executive Compensation*

The officers of our general partner manage and operate our business. We do not directly employ any of the persons responsible for managing or operating our business, but instead reimburse our general partner for the services of such persons. The following table sets forth the compensation paid during or with respect to each of the years 2005, 2004 and 2003 for services rendered on behalf of us to our general partner's Chief Executive Officer and the other four most highly compensated executive officers (collectively, "Named Executive Officers") whose compensation exceeded $100,000 in 2005.

Summary Compensation Table

		Annual Compensation (1)			Long-Term Compensation		
Name and Principal Position	**Year**	**Salary ($)**	**Bonus ($)**	**Other Annual Compensation ($) (2)**	**Restricted Unit Awards ($) (3)**	**All Other Compensation ($) (4)**	**Total Compensation ($) (1) (5)**
A. James Dearlove	2005	176,000	176,500	10,400	238,000	774	601,674
Chief Executive Officer	2004	170,000	110,000	8,716	199,329	774	488,819
	2003	165,000	62,500	6,296	35,715	774	270,285
Keith D. Horton	2005	250,000	200,000	16,000	242,000	828	708,828
President and Chief	2004	217,800	126,000	14,130	139,880	745	498,555
Operating Officer	2003	211,500	72,000	12,186	35,715	745	332,146
Ronald K. Page	2005	200,000	160,000	15,600	199,973	1,522	577,095
Vice President, Corporate	2004	148,500	90,000	12,240	16,950	516	268,206
Development (6)	2003	72,000	28,800	6,840	22,410	373	130,423
Frank A. Pici	2005	121,500	97,500	8,000	140,000	270	367,270
Vice President and Chief	2004	116,500	70,000	6,228	34,970	270	227,968
Financial Officer	2003	113,000	40,000	5,122	23,810	270	182,202
Nancy M. Snyder	2005	105,000	84,000	6,468	120,000	414	315,882
Vice President and	2004	100,000	60,000	4,966	34,970	414	200,350
General Counsel	2003	96,250	40,000	5,109	23,810	414	165,583

(1) Messrs. Dearlove and Pici and Ms. Snyder each devoted approximately 50 percent of his or her professional time to our business and affairs. Messrs. Horton and Page each devoted substantially all of his professional time in 2005 and approximately 90 percent of his professional time in 2004 and 2003 to our business and affairs. Messrs. Dearlove, Horton, Page and Pici and Ms. Snyder each devoted the balance of his or her professional time to the business and affairs of Penn Virginia, which is the indirect sole member of our general partner. For administrative purposes, Penn Virginia paid these amounts directly to Messrs. Dearlove and Pici and Ms. Snyder in 2005, 2004 and 2003 and to Messrs. Horton and Page in 2004 and 2003, and then our general partner reimbursed such amounts to Penn Virginia. Our general partner paid these amounts directly to Messrs. Horton and Page in 2005. The table above does not include amounts paid to the Named Executive Officers in consideration for time devoted to the business and affairs of Penn Virginia.

(2) These amounts reflect car allowances and executive health exams. Penn Virginia paid these amounts directly to Messrs. Dearlove and Pici and Ms. Snyder in 2005, 2004 and 2003 and to Messrs. Horton and Page in 2004 and 2003 and then received reimbursement from our general partner. Our general partner paid these amounts directly to Messrs. Horton and Page in 2005.

(3) These amounts reflect the value on the date of grant of restricted units granted under our general partner's long-term incentive plan. One-third of the restricted units granted in 2005 vested on March 3, 2006. Another one-third of these restricted units will vest on March 6, 2007 if we have made all minimum quarterly distributions payable to unitholders as required under our partnership agreement with respect to all quarters through September 30, 2006. The balance of these restricted units will vest on March 6, 2008 if we have made all minimum quarterly distributions payable to unitholders as required under our partnership agreement with respect to all quarters through September 30, 2006. With respect to the restricted units granted in 2004 and 2003, one-quarter of these restricted units vested on November 12, 2004 and another one-quarter of these restricted units vested on November 14, 2005. The balance of such restricted units will vest on or about November 10, 2006 if we have made all minimum quarterly distributions payable to unitholders as required under our partnership agreement prior to the time of such vesting. Messrs. Dearlove, Horton, Page and Pici and Ms. Snyder received $32,981, $34,612, $9,391, $15,184 and $14,478 of distributions paid with respect to these restricted units in 2005, $25,020, $27,600, $2,390, $11,140 and $11,140 of distributions paid with respect to these restricted units in 2004 and $14,700, $19,850, $780, $8770 and $8,770 of such distributions in 2003. Restricted units may not be transferred, and are subject to forfeiture upon termination of employment, until such time as the restricted units vest. The table below sets forth the number and aggregate market value of restricted units held on December 31, 2005 by each of the named executive officers. The value of these restricted units was determined by multiplying the closing market price of our common units on December 30, 2005 by the number of restricted units held on such date.

Name	Number	Market Value ($)
A. James Dearlove	10,977	609,992
Keith D. Horton	11,451	636,332
Ronald K. Page	4,302	239,062
Frank A. Pici	5,325	295,910
Nancy M. Snyder	4,957	275,460

(4) Reflects reimbursements to Penn Virginia for life insurance premiums paid by Penn Virginia.

(5) Represents the aggregate amount of the "Salary," "Bonus," "Other Annual Compensation," "Restricted Unit Awards" and "All Other Compensation" columns of the Summary Compensation Table.

(6) Mr. Page joined our general partner in July 2003.

Compensation of Directors

Each non-employee director of our general partner receives an annual retainer of $110,000, consisting of $20,000 of cash and $90,000 worth of deferred common units. The actual number of deferred common units awarded in any given year is based upon the fair market value of our common units on the date on which such award is granted. Each deferred common unit represents one common unit representing a limited partner interest in the Partnership, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of our general partner. The Chairperson of the audit committee of the board of directors of our general partner receives an annual cash retainer of $15,000, and each audit committee member receives an annual cash retainer of $10,000. The Chairpersons of all other committees of the board of directors of our general partner receive annual cash retainers of $2,500. In addition to annual retainers, each non-employee director receives $1,000 cash for each board of directors and committee meeting he or she attends. Directors appointed during a year, or who cease to be directors during a year, receive a pro rata portion of cash and deferred common units. Directors may elect to receive any cash payments in common units or deferred common units, and may elect to defer the receipt of any cash or common units they receive under our general partner's Non-Employee Directors Deferred Compensation Plan.

Long-Term Incentive Plan

Our general partner has adopted the Second Amended and Restated Penn Virginia Resource GP, LLC Long-Term Incentive Plan. The long-term incentive plan permits the grant of awards covering an aggregate of 300,000 common units to employees and directors of our general partner and employees of our general partner's affiliates who perform services for us. Awards under the long-term incentive plan can be for 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 our general partner's board of directors.

Our general partner's board of directors in its discretion may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Restricted Units. Our general partner granted 25,488 restricted units to officers and employees of our general partner in 2005. Restricted units vest upon terms established by the compensation and benefits committee, but in no case earlier than the conversion to common units of our outstanding subordinated units. In addition, all restricted units will vest upon a change of control of our general partner or Penn Virginia. If a grantee's employment with, or membership on the board of directors of, our 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 our general partner and made subject to a risk of forfeiture during the applicable restriction period.

Unit Options. The long-term incentive plan also permits the grant of options covering common units. No grants of unit options have been made under the long-term incentive plan. Unit options will have an exercise price that, in the discretion of the compensation and benefits committee, may be less than, equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation and benefits committee. In addition, all unit options will become exercisable upon a change in control of our general partner or Penn Virginia. If a grantee's employment with, or membership on the board of directors of, our general partner terminates for any reason, the grantee's unit options will be automatically forfeited unless, and to the extent, that the compensation and benefits committee provides otherwise. Upon exercise of a unit option, our general partner will acquire common units in the open market or directly from us or any other person or use common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring these common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us.

Phantom Units. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation and benefits committee, the cash equivalent of the value of a common unit. No grants of phantom units have been made under the long-term incentive plan. The compensation and benefits committee will determine the time period over which phantom units granted to employees and directors will vest. In addition, all phantom units will vest upon a change of control of our general partner or Penn Virginia. If a grantee's employment with, or membership on the board of directors of, our general partner terminates for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, the compensation and benefits committee provides otherwise. Common units delivered upon the vesting of phantom units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. The compensation and benefits committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom units.

Deferred Common Units. The long-term incentive plan permits the grant of deferred common units to directors. Our general partner granted 8,855 deferred common units to directors of our general partner in 2005. 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 our general partner. Common units delivered in connection with deferred common units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. Deferred common units awarded to directors receive all cash or other distributions paid by us on account of our common units.

Non-Employee Directors Deferred Compensation Plan

Our general partner has adopted the Penn Virginia Resource GP, LLC Non-Employee Directors Deferred Compensation Plan. The non-employee deferred compensation plan permits the non-employee directors of our general partner to defer the receipt of any or all cash, common units and restricted units they receive as compensation. All deferrals, and any distributions with respect to deferred common units or deferred restricted units, are credited to a deferred compensation account, the cash portion of which is credited quarterly with interest calculated at the prime rate. Non-employee directors of our general partner are fully vested at all times in any cash or deferred common units credited to their deferred compensation accounts. Any restricted unit awards credited to a deferred compensation account are subject to the same vesting and forfeiture restrictions that apply to the underlying award. Amounts held in a non-employee director's deferred compensation account will be distributed to the director on the January 1st following the earlier to occur of the director reaching age 70 or the resignation or removal of the director from the board of directors of our general partner. Upon the death of a non-employee director, all vested amounts held in the deferred compensation account of the non-employee director will be distributed to the director's estate.

Change-in-Control Arrangements

On March 9, 2006, our general partner entered into an Executive Change of Control Severance Agreement (a "General Partner Severance Agreement") with each of Messrs. Horton and Page (the "GP Executives") containing the terms and conditions described below.

Term. Each General Partner Severance Agreement has a two-year term which is automatically extended for consecutive one-day periods until terminated by notice from our general partner. If such notice is given, the General Partner Severance Agreement will terminate two years after the date of such notice.

Triggering Events. Each General Partner Severance Agreement provides severance benefits to the GP Executive upon the occurrence of two events (the "GP Triggering Events"). Specifically, if a change of control of our general partner occurs and, within two years after the date of such change of control, either (a) the GP Executive's employment is terminated for any reason other than for cause or the GP Executive's inability to perform his duties for at least 180 days due to mental or physical impairment or (b) the GP Executive terminates his employment due to a reduction in his authority, duties, title, status or responsibility, a reduction in his base salary, a discontinuation of a material incentive compensation plan in which he participated, our general partner's failure to obtain an agreement from its successor to assume his General Partner Severance Agreement or the relocation by more than 100 miles of our general partner's office at which he was working at the time of the change of control, then the GP Executive may elect to receive the change of control severance payments and other benefits described below.

Change of Control Severance Benefits. Upon the occurrence of the GP Triggering Events, the GP Executive may elect to receive a lump sum, in cash, of an amount equal to three times the sum of his annual base salary plus the highest cash bonus paid to him during the two-year period prior to termination, subject to reduction as described below under "Excise Taxes." In addition, all options to purchase Penn Virginia stock then held by the GP Executive will immediately vest and will remain exercisable for the shorter of three years or the remainder of the options' respective terms and all restricted Penn Virginia stock and all restricted units then held by Mr. Horton will immediately vest and all restrictions will lapse. Our general partner will also provide certain health and dental benefit related payments to the GP Executive as well as certain outplacement services. Our general partner will not be entitled to reimbursement from us for any of the change of control severance payments or other benefits described in this paragraph.

Excise Taxes. If our general partner's independent registered public accountants determine that any payments to be made or benefits to be provided to the GP Executive under his General Partner Severance Agreement would result in him being subject to the excise tax imposed by Section 4999 of the Internal Revenue Code, such payments or benefits will be reduced to the extent necessary to prevent him from being subject to such excise tax.

Compensation Committee Interlocks and Insider Participation

During 2005, Messrs. Cloues, DesBarres, Jarrett and Montague served on the compensation and benefits committee of our general partner. None of these members is a former or current officer or employee of us or any of our subsidiaries or had any relationship requiring disclosure under Item 404—Certain Relationships and Related Transactions of Regulation S-K. In 2005, none of the executive officers of our general partner served as a member of the board of directors or compensation committee of any entity that has one or more executive officers serving on the board of directors or the compensation and benefits committee of our general partner.

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

The following table sets forth, as of March 8, 2006, the amount and percentage of our outstanding common units and subordinated units beneficially owned by (i) each person known by us to own beneficially more than five percent of our common units or our subordinated units, (ii) each director of our general partner, (iii) each executive officer of our general partner and (iv) all directors and executive officers of our general partner as a group.

Name of Beneficial Owners	Common Units (1)	Percentage of Common Units (2)	Subordinated Units (1)	Percentage of Subordinated Units(2)	Percentage of Total Units
Penn Virginia Resource LP Corp. (3)	3,469,820	20.4	3,567,521	93.3	33.8
Kanawha Rail Corp (3)	267,887	1.6	257,419	6.7	2.5
Penn Virginia Resource GP, LLC (3)	156,777	—	—	—	—
Edward B. Cloues, II	9,207 (4)	—	—	—	—
A. James Dearlove	29,112 (5)	—	—	—	—
John P. DesBarres	19,930 (6)	—	—	—	—
James L. Gardner	411 (7)	—	—	—	—
Keith D. Horton	29,306 (8)	—	—	—	—
Keith B. Jarrett	11,246 (4)	—	—	—	—
James R. Montague	9,746 (9)	—	—	—	—
Ronald K. Page	9,599 (10)	—	—	—	—
Marsha R. Perelman	2,698 (11)				
Frank A. Pici	13,620 (12)	—	—	—	—
Nancy M. Snyder	13,225 (13)	—	—	—	—
All directors and executive officers as a group (11 persons)	148,100 (14)	—	—	—	—

(1) Unless otherwise indicated, all units are owned directly by the named holder and such holder has sole power to vote and dispose of such units.
(2) Based on 16,997,325 common units and 3,824,940 subordinated units issued and outstanding on March 8, 2006. On March 8, 2006, there were approximately 17,000 holders of our common units and two holders of our subordinated units. Unless otherwise indicated, beneficial ownership is less than one percent of our common units and/or subordinated units.
(3) Penn Virginia is the ultimate parent company of Penn Virginia Resource LP Corp., Kanawha Rail Corp. and Penn Virginia Resource GP, LLC. As such, Penn Virginia may be deemed to beneficially own the units held by Penn Virginia Resource LP Corp., Kanawha Rail Corp. and Penn Virginia Resource GP, LLC, which together own 22.9 percent of our common units and 100 percent of our subordinated units. The address for each of Penn Virginia Resource LP Corp., Kanawha Rail Corp. and Penn Virginia Resource GP, LLC is c/o Penn Virginia Corporation, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087.
(4) Includes 2,000 restricted units which are currently subject to a restriction against transfer and an obligation to forfeiture to our general partner upon termination of board membership for any reason other than death. Such restrictions lapse at the same time and in the same proportion as our outstanding subordinated units are converted to common units during the Subordination Period (as defined in our partnership agreement). See Item 11, "Executive Compensation—Long Term Incentive Plan." Also includes 2,246 deferred common units.
(5) Includes 16,012 restricted units and 100 common units held by Mr. Dearlove for the benefit of a minor.
(6) Includes 2,000 restricted units, 1,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 2,930 deferred common units.
(7) Reflects 411 deferred common units.
(8) Includes 17,506 restricted units and 500 common units held by Mr. Horton's spouse.

(9) Includes 2,000 restricted units, 1,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 2,246 deferred common units.
(10) Includes 8,974 restricted units.
(11) Includes 1,634 deferred common units.
(12) Includes 8,370 restricted units.
(13) Includes 7,500 restricted units and 150 common units held by Ms. Snyder for the benefit of a minor child.
(14) Includes 66,362 restricted units, 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan, 11,713 deferred common units, 250 common units held by executive officers for the benefit of minors and 500 common units held by Mr. Horton's spouse.

The following table sets forth certain information as of December 31, 2005, regarding the options outstanding and securities issued and to be issued under our general partner's equity compensation plans not approved by our unitholders. Our general partner does not have any equity compensation plans which were approved by our unitholders.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)
	(a)	(b)	(c)
Equity compensation plans approved by unitholders	N/A	N/A	N/A
Equity compensation plans not approved by unitholders	0	N/A	186,508

Item 13 *Certain Relationships and Related Transactions*

We are managed and controlled by our general partner pursuant to our partnership agreement. Under our partnership agreement, our general partner is reimbursed for all direct and indirect expenses it incurs or payments it makes on our behalf. These expenses include salaries, fees and other compensation and benefit expenses of employees, officers and directors, insurance, other administrative or overhead expenses and all other expenses necessary or appropriate to conduct our business. The costs allocated to us by our general partner for administrative services and overhead totaled \$2.6 million, \$1.5 million and \$1.1 million for the years ended December 31, 2005, 2004 and 2003.

Our partnership agreement provides for incentive distributions payable to our general partner out of our Available Cash (as defined in our partnership agreement) in the event quarterly distributions to unitholders exceed certain specified targets. In general, subject to certain limitations, if a quarterly distribution exceeds a target of \$0.55 per common unit, our general partner will receive incentive distributions equal to (i) 15 percent of that portion of the distribution per common unit which exceeds but is not more than \$0.65, plus (ii) 25 percent of that portion of the quarterly distribution per common unit which exceeds \$0.65 but is not more than \$0.75, plus (iii) 50 percent of that portion of the quarterly distribution per common unit which exceeds \$0.75. In 2005, our general partner received total distributions, including incentive distributions, of \$21.2 million. See also Item 1, "Business—Ownership by and Relationship with Penn Virginia Corporation."

Item 14 *Principal Accounting Fees and Services*

In connection with the audits of our and our general partner's financial statements and our internal control over financial reporting ("ICFR") for 2005, we entered into an agreement with KPMG which sets forth the terms by which KPMG will perform audit services for us. That agreement is subject to alternative dispute resolution procedures, an exclusion of the right to collect punitive damages and various other provisions. The following table shows fees for professional audit services rendered by KPMG for the audit of our and our general partner's annual financial statements for 2005 and 2004, the audit of our ICFR and fees billed for other services rendered by KPMG.

	2005	2004
Audit Fees (1)	$ 668,300	$ 434,800
Audit-Related Fees (2)	5,000	14,200
Tax Fees	—	—
All Other Fees	—	—
Total Fees	$ 673,300	$ 449,000

(1) Audit fees consist of fees for the audits of our and our general partner's financial statements, the audit of our ICFR, consents for registration statements and comfort letters. Also included in audit fees are reimbursements of travel-related expenses.

(2) Audit-related fees in 2005 and 2004 included $5,000 pertaining to debt compliance letters issued by KPMG for the Notes. In 2004, we paid additional audit-related fees of $9,200 pertaining to accounting consultations related to acquisitions. There were no such fees in 2005.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountants

The policy of the audit committee of our general partner is to pre-approve all audit, audit-related and non-audit services provided by the independent registered public accountants. These services may include audit services, audit-related services, tax services and other services. The audit committee may also pre-approve particular services on a case-by-case basis. The independent registered public accountants are required to periodically report to the audit committee regarding the extent of services provided by the independent registered public accountants in accordance with such pre-approval. The audit committee may also delegate pre-approval authority to one or more of its members. Such member(s) must report any decisions to the audit committee at the next scheduled meeting.

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 38 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) Certificate of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.1 to Registrant's Form S-1 filed on July 19, 2001).

(3.2) First Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(3.3) Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(3.4) Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.4 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

(3.5) Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.5 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

(3.6) Certificate of Formation of Penn Virginia Operating Co., LLC (incorporated by reference to Exhibit 3.3 to Amendment No. 2 to Registrant's Form S-1 filed on October 4, 2001).

(3.7) Form of Amended and Restated Limited Liability Company Agreement of Penn Virginia Operating Co., LLC (incorporated by reference to Exhibit 3.4 to Amendment No. 3 to Registrant's Form S-1 filed on October 16, 2001).

(3.8) Certificate of Formation of Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 3.5 to Amendment No. 1 to Registrant's Form S-1 filed on September 7, 2001).

(3.9) Third Amended and Restated Limited Liability Company Agreement of Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 3.7 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(4.1) Note Purchase Agreement dated as of March 27, 2003 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on April 2, 2003).

(4.2) First Amendment to Note Purchase Agreement and Parent Guaranty dated as of March 3, 2005 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 9, 2005).

(10.1) Amended and Restated Credit Agreement dated as of March 3, 2005 among Penn Virginia Operating Co., LLC, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 9, 2005).

(10.2) First Amendment, Waiver, and Consent to Amended and Restated Credit Agreement dated as of July 15, 2005 among Penn Virginia Operating Co., LLC, PNC Bank, National Association, as agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 21, 2005).

(10.3) Contribution and Conveyance Agreement dated September 13, 2001 among Penn Virginia Operating Co., LLC, Penn Virginia Holding Corp., Penn Virginia Resource Holdings Corp., Penn Virginia Resource LP Corp., Penn Virginia Resource GP Corp. and the other parties named therein (incorporated by reference to Exhibit 10.2 to Amendment No. 2 to Registrant's Form S-1 filed on October 4, 2001).

(10.4) Contribution, Conveyance and Assumption Agreement dated September 14, 2001 among Penn Virginia Resource GP, LLC, Penn Virginia Resource Partners, L.P., Penn Virginia Operating Co., LLC and the other parties named therein (incorporated by reference to Exhibit 10.3 to Amendment No. 2 to Registrant's Form S-1 filed on October 4, 2001).

(10.5) Closing Contribution, Conveyance and Assumption Agreement dated October 30, 2001 among Penn Virginia Operating Co., LLC, Penn Virginia Corporation, Penn Virginia Resource Partners, L.P., Penn Virginia Resource GP, LLC, Penn Virginia Resource L.P. Corp., Wise LLC, Loadout LLC, PVR Concord LLC, PVR Lexington LLC, PVR Savannah LLC, Kanawha Rail Corp. (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to Registrant's Form S-1 filed on October 4, 2001).

(10.6) Omnibus Agreement dated October 30, 2001 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 10.6 to Amendment No. 2 to Registrant's Form S-1 filed on October 4, 2001).

(10.7) 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 10.7 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.8) Penn Virginia Resource GP, LLC Second Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 27, 2006).*

(10.9) Form of deferred common unit agreement (incorporated by reference to Exhibit 10.7 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.10) Form of restricted unit award agreement (incorporated by reference to Exhibit 10.8 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.11) Penn Virginia Resource GP, LLC Short-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Amendment No. 2 to Registrant's Form S-1 filed on October 4, 2001).*

(10.12) Penn Virginia Resource GP, LLC Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.7 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).*

(10.13) Coal Mining Lease dated December 19, 2002 between Suncrest Resources LLC and Sterling Smokeless Coal Company (incorporated by reference to Exhibit 10.8 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.14) Coal Mining Lease and Sublease dated December 19, 2002 between Fieldcrest Resources LLC and Gallo Finance Company (incorporated by reference to Exhibit 10.9 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.15) Purchase and Sale Agreement dated as of December 19, 2002 by and among Peabody Energy Corporation, Eastern Associated Coal Corp., Peabody Natural Resources Company and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on January 2, 2003).

(10.16) Purchase and Sale Agreement dated as of July 1, 2004 by and among A. T. Massey Coal Company, Inc., Marten County Coal Corporation, Tennessee Consolidated Coal Co., Tennessee Energy Corp. and Road Fork Development Company, Inc. and Loadout LLC and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on July 20, 2004).

(10.17) 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).*

(10.18) 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 Penn Virginia Resource Partners, L.P.

(23.1) Consent of KPMG LLP.

(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.

(99.1) Balance sheet dated as of December 31, 2005 of Penn Virginia Resource GP, LLC and Independent Auditors' Report.

* 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 RESOURCE PARTNERS, L.P.

By: PENN VIRGINIA RESOURCE GP, LLC

March 16, 2006

By: /s/ FRANK A. PICI

(Frank A. Pici, Vice President and
Chief Financial Officer)

March 16, 2006

By: /s/ FORREST W. MCNAIR

(Forrest W. McNair, Vice President and
Principal Accounting Officer)

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/ A. JAMES DEARLOVE **(A. James Dearlove)**	Chairman of the Board and Chief Executive Officer	March 16, 2006
/s/ EDWARD B. CLOUES, II **(Edward B. Cloues, II)**	Director	March 16, 2006
/s/ JOHN P. DESBARRES **(John P. DesBarres)**	Director	March 16, 2006
/s/ JAMES L. GARDNER **(James L. Gardner)**	Director	March 16, 2006
/s/ KEITH B. JARRETT **(Keith B. Jarrett)**	Director	March 16, 2006
/s/ JAMES R. MONTAGUE **(James R. Montague)**	Director	March 16, 2006
/s/ MARSHA R. PERELMAN **(Marsha R. Perelman)**	Director	March 16, 2006
/s/ FRANK A. PICI **(Frank A. Pici)**	Vice President, Chief Financial Officer and Director	March 16, 2006
/s/ NANCY M. SNYDER **(Nancy M. Snyder)**	Vice President, General Counsel and Director	March 16, 2006