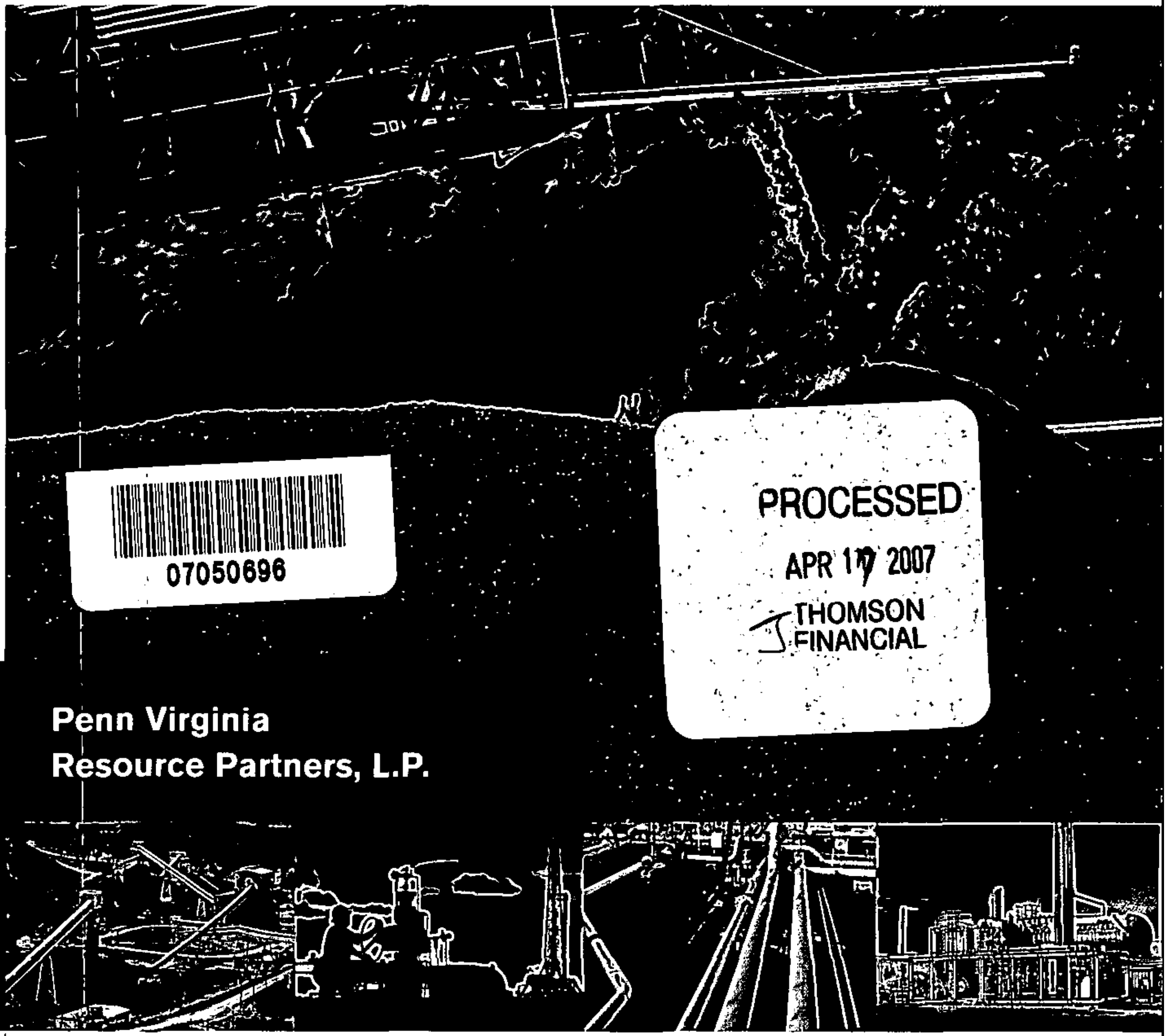
2006 ANNUAL REPORT





# Penn Virginia Resource Partners, L.P.

*Delivering on the Strategy*

Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a master limited partnership formed by Penn Virginia Corporation (NYSE: PVA). The Partnership manages coal properties and related assets and operates a midstream natural gas gathering and processing business. PVR is headquartered in Radnor, PA. For more information about PVR, visit the Partnership's website at www.pvresource.com.

## Financial Highlights

| In millions, except per unit information | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| **Financial Data** | | | | | |
| Net revenues[1] | $ 183.3 | $ 142.4 | $ 75.6 | $ 55.6 | $ 38.6 |
| Operating income | 102.8 | 78.1 | 40.5 | 26.6 | 24.4 |
| Net income | 73.9 | 51.2 | 34.3 | 22.7 | 24.7 |
| Cash flow from operations | 107.3 | 93.7 | 54.8 | 41.1 | 30.3 |
| Distributable cash flow[2] | 100.2 | 85.5 | 52.8 | 39.3 | 28.5 |
| Total assets | 714.0 | 657.9 | 284.4 | 259.9 | 266.6 |
| Long-term debt, excluding current portion | 207.2 | 246.8 | 112.9 | 90.3 | 90.9 |
| Partners' capital | 402.2 | 284.0 | 150.0 | 153.8 | 162.5 |
| Long-term debt as percent of total capitalization | 34% | 46% | 43% | 37% | 36% |
| **Per Limited Partner Unit Data[3]** | | | | | |
| Net income[4] | $ 1.56 | $ 1.22 | $ 0.93 | $ 0.62 | $ 0.79 |
| Cash distributions declared[5] | 1.60 | 1.30 | 1.08 | 1.04 | 1.00 |
| Weighted average number of limited partner units outstanding | 42.0 | 40.3 | 36.1 | 35.9 | 30.8 |
| **Operating Data** | | | | | |
| Coal produced by lessees (millions of tons) | 32.8 | 30.2 | 31.2 | 26.5 | 14.3 |
| Coal royalties ($/ton) | $ 2.99 | $ 2.74 | $ 2.23 | $ 1.90 | $ 2.20 |
| Estimated coal reserves (millions of recoverable tons) | 765 | 689 | 558 | 588 | 615 |
| Natural gas system volumes[6] | 163 | 127 | — | — | — |

[1] 2006 and 2005 amounts are shown net of cost of gas purchased of $335 million and $304 million, respectively.

[2] Distributable cash flow is calculated as follows:

| | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Operating income | $ 102.8 | $ 78.1 | $ 40.5 | $ 26.6 | $ 24.4 |
| Depreciation, depletion and amortization | 37.5 | 30.6 | 18.6 | 16.6 | 4.0 |
| Derivative losses (gains) included in operations | 1.9 | (1.0) | — | — | — |
| Cash paid for derivative settlements | (19.4) | (4.7) | — | — | — |
| Interest expense, net | (17.6) | (12.9) | (6.2) | (3.8) | 0.3 |
| Maintenance capital expenditures | (9.5) | (4.6) | (0.1) | (0.1) | (0.1) |
| Other | 4.5 | — | — | — | — |
| Distributable cash flow | $ 100.2 | $ 85.5 | $ 52.8 | $ 39.3 | $ 28.5 |

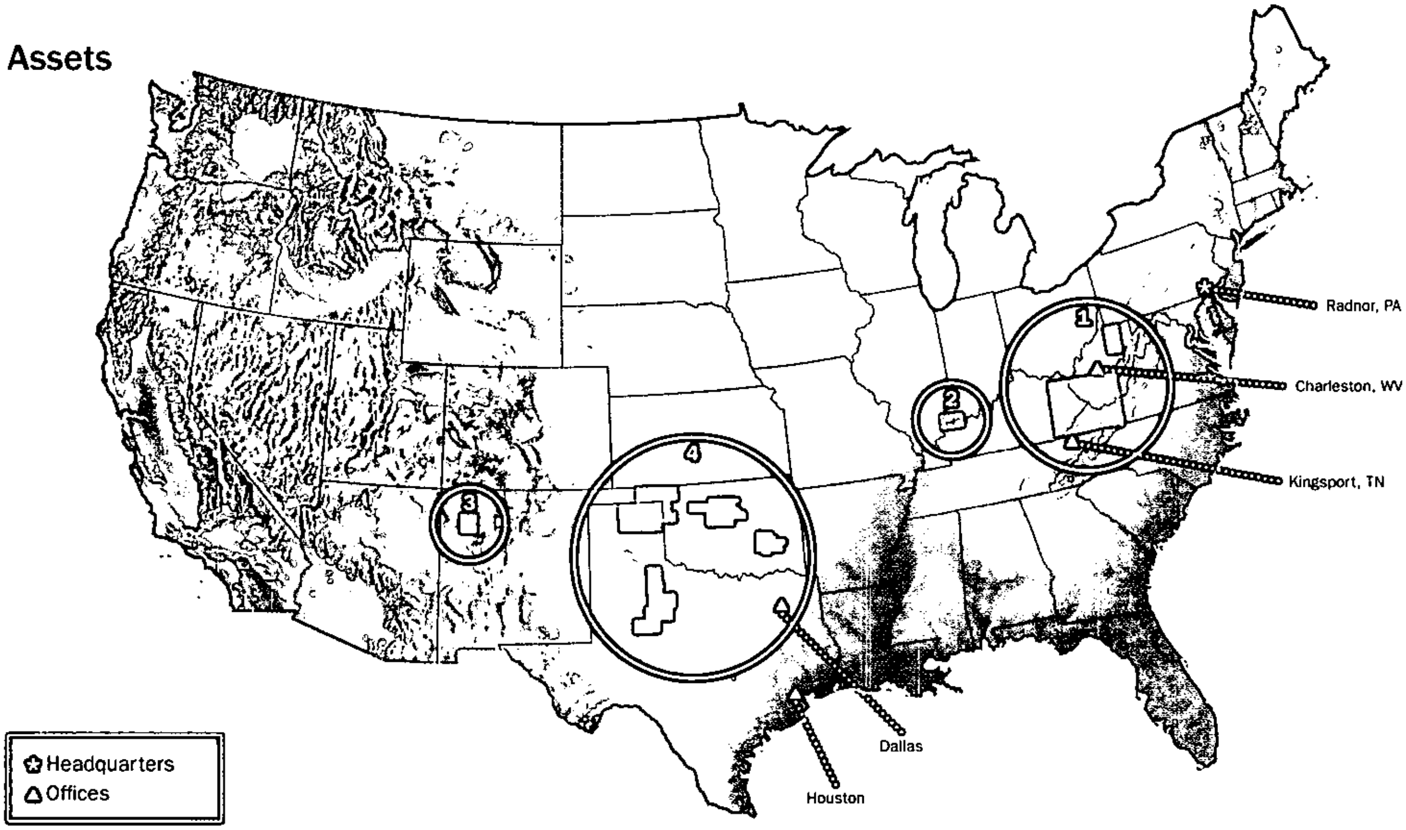
[3] Per unit data reflects 2-for-1 unit split in April 2006.

[4] Per unit amount is computed after general partner's share.

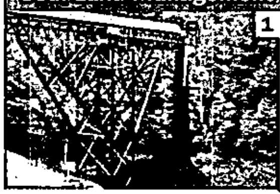
[5] Annualized as of last distribution paid in year.

[6] Reflects mid-2006 Transwestern acquisition as if acquired on January 1, 2006 and ten-month results in 2005.

# Assets




## Coal Land Management



**1**

### Central Appalachia
559 million tons of high-quality coal reserves; coal services and infrastructure investments

### Northern Appalachia
36 million tons of mid-to-high sulfur coal reserves

**2**

### Illinois Basin
113 million tons of high sulfur coal reserves

**3**

### San Juan Basin
58 million tons of midsulfur coal reserves

## Natural Gas Midstream

**4**

### Mid-Continent Natural Gas Midstream Operations

**Beaver/Perryton System**
Gathering pipelines – 1,377 miles
Processing plant – 100 MMcfd

**Hamlin System**
Gathering pipelines – 497 miles
Processing plant – 20 MMcfd

**Crescent System**
Gathering pipelines – 1,679 miles
Processing plant – 40 MMcfd

**Arkoma System**
Gathering pipelines – 78 miles

# Strategy for Growth

## Coal Land Management

- Continue to grow coal reserve holdings in multiple basins
- Expand coal services and infrastructure business on PVR properties
- Grow coal infrastructure business, which provides handling and processing services to operators and end users
- Consider acquisitions of other types of royalty-based cash streams, such as natural gas royalties

## Natural Gas Midstream

- Identify and acquire additional gathering, processing and related assets, including diversification into new areas
- Expand existing systems by connecting new wells to PVRM's current gathering and processing systems
- Develop ways to increase service level to Penn Virginia Corporation's oil and gas exploration and production business

## Financial Discipline

- Fund growth with a combination of debt and new unit issuances
- Continue to increase distributions at a rate competitive with other MLPs, after reviewing reinvestment needed to sustain long-term growth

A. James Dearlove
*Chairman and Chief Executive Officer*

# Dear Fellow Unitholder:

Penn Virginia Resource Partners, L.P. (PVR) had another record year in 2006, setting new highs for revenue, operating income, net income, cash flow from operations and distributable cash flow.

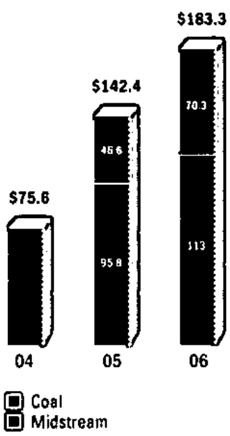
PVR also enjoyed record-setting coal production by its lessees and record natural gas midstream volumes. On three separate occasions during 2006, cash distributions to unitholders were increased, resulting in an aggregate increase of 23 percent, from $1.30 per unit annualized in the fourth quarter of 2005 to $1.60 per unit annualized in the same quarter of 2006. Since its initial public offering in 2001, cash distributions to unitholders have been increased on eight separate occasions at a compound annual growth rate of nine percent.

During 2006, worldwide and domestic demand for coal continued to be strong as record warmth and a vibrant economy fueled domestic power demand. Natural gas prices remained high relative to coal during the year, despite record natural gas storage volumes, and helped keep coal the fuel of choice for domestic electricity generation. PVR's coal land management business benefited from strong coal pricing, as its average royalties per ton in 2006 were nine percent higher than in 2005.

We expanded our coal business during 2006, completing coal reserve acquisitions in both central Appalachia and the Illinois Basin which added approximately 96 million tons of coal for approximately $76 million. Central Appalachia is an area of high quality coal in which we have owned coal reserves since 1882. The Illinois Basin is expected to be a growth area for PVR because of the basin's proximity to power plants and because we expect future environmental regulations to require scrubbing of most coals, which will increase the competitiveness of the Illinois Basin coals. We expect to continue to diversify our coal reserve holdings into various domestic basins.

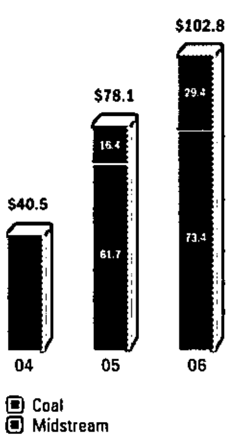
PVR's natural gas midstream segment also contributed to our record-setting financial performance in 2006. In its first full year of operations, this business, which we operate as PVR Midstream, provided PVR with significant additional operating income and cash flow, particularly in the second half of the year when record processing margins, or "frac" spreads, were experienced.

**NET REVENUES[a,b]**
Dollars in millions




*(a) 2006 and 2005 amounts are shown net of cost of gas purchased of $335 million and $304 million, respectively.*

**OPERATING INCOME[b]**
Dollars in millions




*(b) In 2005, ten months of results for natural gas midstream.*

## 2006 Key Events

- Record distributable cash flow, operating income and net income during 2006
- Record lessee coal production during 2006
- Increasing natural gas midstream inlet volumes
- Increased cash distributions on three occasions during the year
- Added 96 million tons of coal reserves in three acquisitions, including two in central Appalachia and one in the Illinois Basin
- Acquired midstream assets contiguous to our largest system in the Panhandle of Texas and western Oklahoma
- Reduced debt at the end of 2006 with the proceeds from the sale of limited partner units to PVG
- Continued to explore ways to provide services to Penn Virginia Corporation's oil and gas exploration and production business

PVR Midstream is expected to continue to be a growth platform for PVR, both from organic growth, by tying new natural gas production to existing systems, and from acquisitions in the natural gas midstream sector. In June 2006, we completed a $15 million acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma which complements our existing midstream system.

In December 2006, Penn Virginia Corporation completed the $128 million initial public offering of Penn Virginia GP Holdings, L.P. (NYSE:PVG), which owns the general partner of and incentive distribution rights in PVR, as well as approximately 42 percent of the limited partner interests in PVR. Approximately $115 million of proceeds from the offering were invested in additional PVR limited partnership units which were retained by PVG. PVR, in turn, used the proceeds from that sale to repay a significant portion of its bank debt.

This transaction strengthened PVR's balance sheet and improved the terms of the credit facility by lowering interest rates (and interest expense in the aggregate) and by increasing the amount of capital available under the credit facility. PVG's IPO also established a stand-alone general partner holding vehicle which can be used in the future to support PVR's growth.

The strengthened balance sheet, establishment of a stand-alone and separately financed general partner holding partnership, two growth platforms in strong industries, and a seasoned, proven management team make PVR well positioned for the future. We appreciate your investment in Penn Virginia Resource Partners and value your continued support.

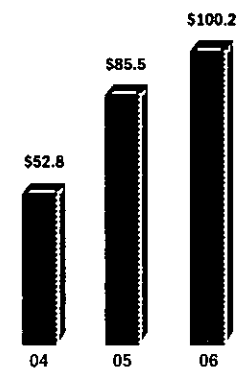
James Dearlove

**A. James Dearlove**
*Chairman and Chief Executive Officer*

**CASH DISTRIBUTIONS DECLARED[a]**
*Per LP unit*


*(a) Annualized as of last distribution paid in year*

**DISTRIBUTABLE CASH FLOW**
*Dollars in millions*

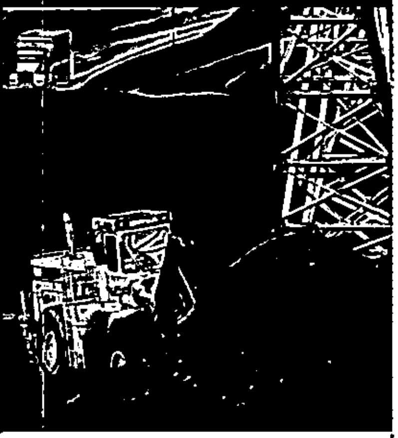



## 2007 Outlook for PVR

Demand for power continues to increase in the U.S. which is favorable for coal prices and natural gas prices, rig counts and the number of producing wells. In addition, the demand for fossil-based fuels continues to increase worldwide, due to ever increasing demand in developing countries.

Interest rates declined in late 2006 and may continue to decline as the efforts of the Federal Reserve to control inflation by raising rates may have largely peaked. This should help the unit price performance of MLPs, including PVR. The decision in Canada in 2006 to tax royalty trusts should also result in higher investment levels in U.S.-based MLPs. The number of MLPs and the size of the universe of potential MLP investors is increasing due to a larger number of yield-seeking "baby boomer" investors and a greater number of institutional investors that have taken steps to enable themselves to invest in MLPs and other similar securities.

MLPs and similar entities continue to be active buyers of long-lived energy assets with stable production and cash flow profiles. That trend should continue as the number of these entities and amounts of low-cost capital continues to increase.



PVR's coal land management business set a new record for revenues in 2006, up 18 percent to $113.0 million from $95.8 million in 2005. Coal royalty revenue was the largest contributor to the year-over-year increase, up $15.5 million, or 19 percent, to $98.2 million. Driven primarily by production growth, 2006 operating income in this segment increased 19 percent to $73.4 million from $61.7 million in 2005.

**COAL ROYALTY REVENUE**
*Dollars in millions*


**COAL ROYALTIES**
*Per Ton*


As of December 31, 2006, PVR owned or controlled approximately 765 million tons of proven and probable coal reserves, an increase of 11 percent from the prior year. PVR's reserves are located in central Appalachia, northern Appalachia, the San Juan Basin and the Illinois Basin. Coal production by PVR's lessees increased nine percent to 32.8 million tons in 2006, from 30.2 million tons in 2005, primarily due to acquisitions, with 1.2 million tons of the increase attributable to central Appalachia and 1.1 million tons of the increase attributable to the Illinois Basin.

PVR completed three coal reserve acquisitions during 2006, adding approximately 96 million tons of coal for a total acquisition cost of approximately $76 million. Approximately 74 million of those tons consist of high quality coal located in central Appalachia.

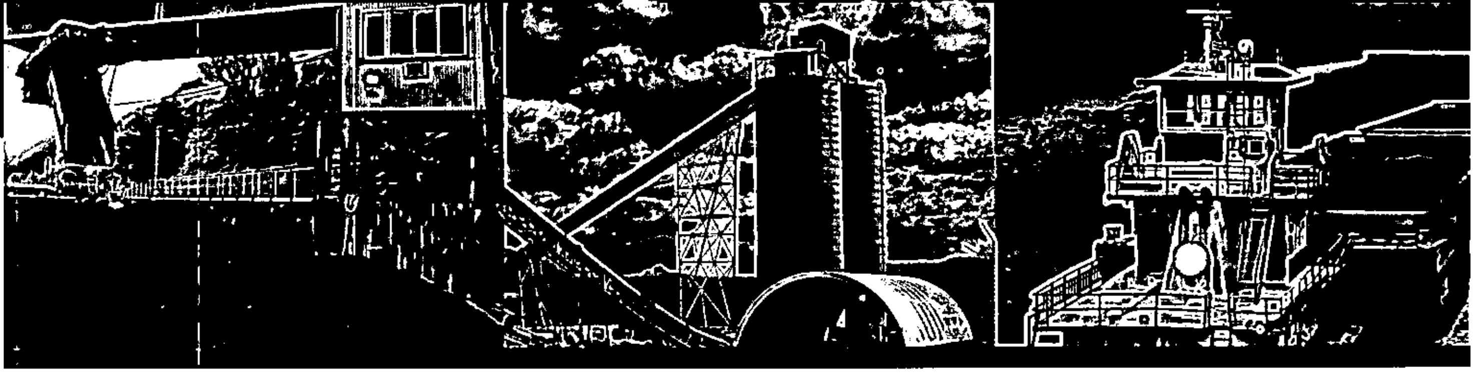
Approximately 22 million tons of the coal PVR acquired is in the western Kentucky portion of the Illinois Basin. The Illinois Basin acquisition complements the approximate 94 million tons of western Kentucky coal PVR purchased in 2005. PVR believes that production from the Illinois Basin will accelerate as environmental regulations become more stringent and as technological advances make it environmentally acceptable to use the basin's high sulfur coal. As a result, PVR plans to increase its position in the Illinois Basin over time.

## Environmental and Safety Awards for PVR and Lessees

On January 12, 2007, at the 34th West Virginia Annual Mining Symposium, one of PVR's subsidiaries, Loadout, LLC, was presented a 2006 Reclamation Award from the State of West Virginia and the West Virginia Coal Association (WVCA) for "innovative and successful techniques demonstrated in the construction of a wetland treatment system which effectively eliminated acid mine drainage from 1,500 acres of a 30-year old underground mining complex." One of PVR's lessees also received a reclamation award for work done in the coal preparation plant and refuse area on the property.

The award reflects work done at an acid mine drainage discharge into Trace Fork of Cabin Creek. The flow of over 125 gallons per minute had an iron content of greater than 10 parts per million and would turn the creek to an unsightly color if left untreated. Prior to the development of the wetland system by Gary Persinger, property engineer for PVR in Chesapeake, WV, the water was treated with conventional chemical techniques utilizing large amounts of caustic soda. The new wetlands were developed at a nominal cost and require minimal attention other than required discharge sampling. Mr. Persinger has developed a total of 12 wetland treatment systems on the property, and all are performing as designed. These systems have been visited by the West Virginia Department of Environmental Protection for training purposes for their enforcement personnel.

Mountaineer Safety Guardian Awards were also made at the Symposium by the West Virginia Office of Miners Health, Safety and Training, and the WVCA. Receiving these safety awards, which were presented to mines having exemplary safety records in the State of West Virginia for the year 2006, were three lessees of PVR: Coal River Energy, Eastern Associated Coal Corp. and Kanawha Eagle.



*In the coal land management business since 1882, Penn Virginia Corporation spun off PVR in 2001. PVR has grown its high-quality reserve base by 55 percent since the end of 2001, diversifying reserves away from its Appalachian roots into other promising areas such as the Illinois Basin, and 2006 lessee coal production was 114 percent higher than in 2001.*

During 2006, worldwide and domestic demand for coal and other hydrocarbons continued to be strong, although coal prices began to decline from their highs during the fourth quarter. We believe the decline in coal prices will primarily impact operators who have a high cost structure, and also operators who do not have long-term contracts in place. In PVR's case, most of our lessees tend to be low-cost operators who have long-term contracts with most of their customers.

In 2006, approximately 70 percent of the coal produced from our properties required our lessees to pay us royalties based on a percentage of the price they received for selling the coal. Most of that coal is sold by our lessees under long-term contracts. Prices under those contracts, increased significantly for contracts renewed during 2005 and 2006. The royalties we received on the other 30 percent of coal produced from our properties were based on fixed rates per ton, which escalate annually. As a result of these factors, our average royalty rates in 2006 increased nine percent to $2.99 per ton from $2.74 per ton in 2005.

We will continue our efforts to build a coal services and infrastructure business. Currently, we own and lease to various operators who mine on our properties, facilities that process and load coal onto railroad cars. We also plan to add to our coal handling business which serves the end users of coal, such as power plants.

Despite anticipated production increases, it is and will continue to be very difficult for the coal mining industry to sustain increased production in Appalachia. The reasons include the depletion of easily accessed reserves, the time-consuming and challenging process of permitting new mines, and an aging workforce that is hard to replace.

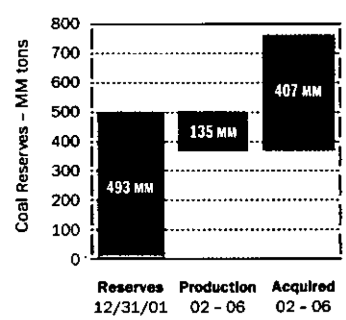
While expanding our coal reserve position, we have also continued to grow our coal services and infrastructure business. We expanded our fleet of coal processing and loading facilities by constructing a new facility that commenced service in October 2006. In addition, we continued to work to expand Coal Handling Solutions, our joint venture with Massey Energy Company [NYSE: MEE], in which we provide coal handling facilities and services for industrial end users.

**YEAR-END 2006 COAL RESERVES**
*MM tons*


| | |
|---|---|
| ■ Central Appalachia | 559 |
| ■ Northern Appalachia | 36 |
| ■ Illinois Basin | 113 |
| ■ San Juan Basin | 58 |
| Total | 765* |

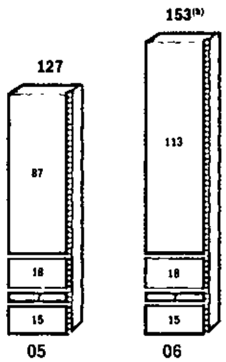
* *does not add due to rounding*

**COAL RESERVES**



Through PVR Midstream, we own and operate natural gas midstream assets that include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing facilities located in Oklahoma and Texas, which have 160 million cubic feet per day (or MMcfd) of total capacity.

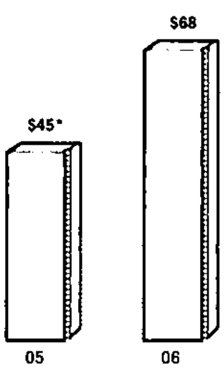
**2006 INLET VOLUMES[a]**
*MMcf per day*




| | | | |
|---|---|---|---|
| 2005 | Beaver System | 69% |
| | Crescent System | 14% |
| | Hamlin System | 5% |
| | Arkoma System[c] | 12% |
| 2006 | Beaver System | 74% |
| | Crescent System | 12% |
| | Hamlin System | 4% |
| | Arkoma System[c] | 10% |

*[a] 10 month data for 2005*
*[b] 163MMcfd, assuming full year of Transwestern acquisition*
*[c] Gathering volumes only*

**2006 PROCESSING MARGINS**
*Dollars in Millions*




** 10 month data for 2005*

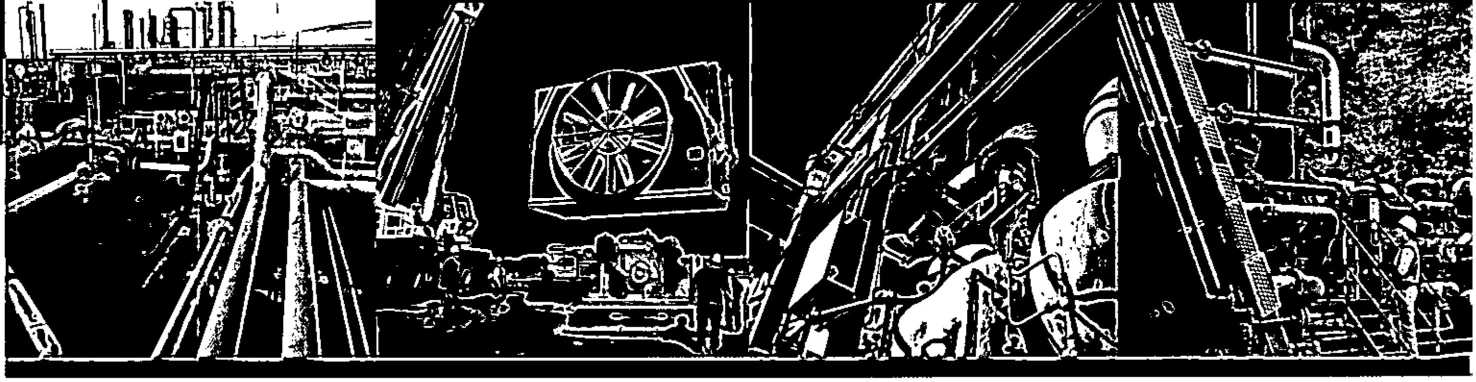
We derive revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We also operate a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

We commenced our natural gas midstream operations through the acquisition of Cantera Gas Resources, LLC in March 2005. We believe that this 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 these assets, we have expanded our natural gas midstream business by acquiring or constructing 181 miles of new gathering lines (see Transwestern Acquisition inset on following page).

For the year ended December 31, 2006, inlet volumes at our gas processing plants and gathering systems, including gathering only volumes, were 56.0 billion cubic feet (or Bcf), or approximately 153 MMcfd (163 MMcfd if the Transwestern Acquisition had occurred at the beginning of 2006). Gross midstream processing margin increased to $68.1 million, or $1.22 per thousand cubic feet (Mcf), for 2006 from the $44.7 million, or $1.15 per Mcf, for the ten months in 2005 that we owned the midstream operations. Midstream operating income in 2006 was $29.4 million, or 29 percent of PVR's total.

Much of PVR's profitability depends on the relationship between the price it receives for the natural gas liquids (NGLs) it extracts and sells at its processing plants and the price of natural gas it buys as feedstock. The difference between these two prices, the so-called "frac spread", can be volatile and difficult to predict. Therefore, PVR employs various hedges to protect its margins and help insure a steady, predictable cash flow stream.

We also continue to explore potential operating synergies with Penn Virginia Corporation's oil and gas exploration and production business. For example, we currently market a significant portion of PVA's natural gas production, which we believe allows PVA to realize higher prices for its oil and natural gas. We are also looking at opportunities to build midstream assets for PVA to allow PVA to maximize the revenue from hydrocarbons it produces.



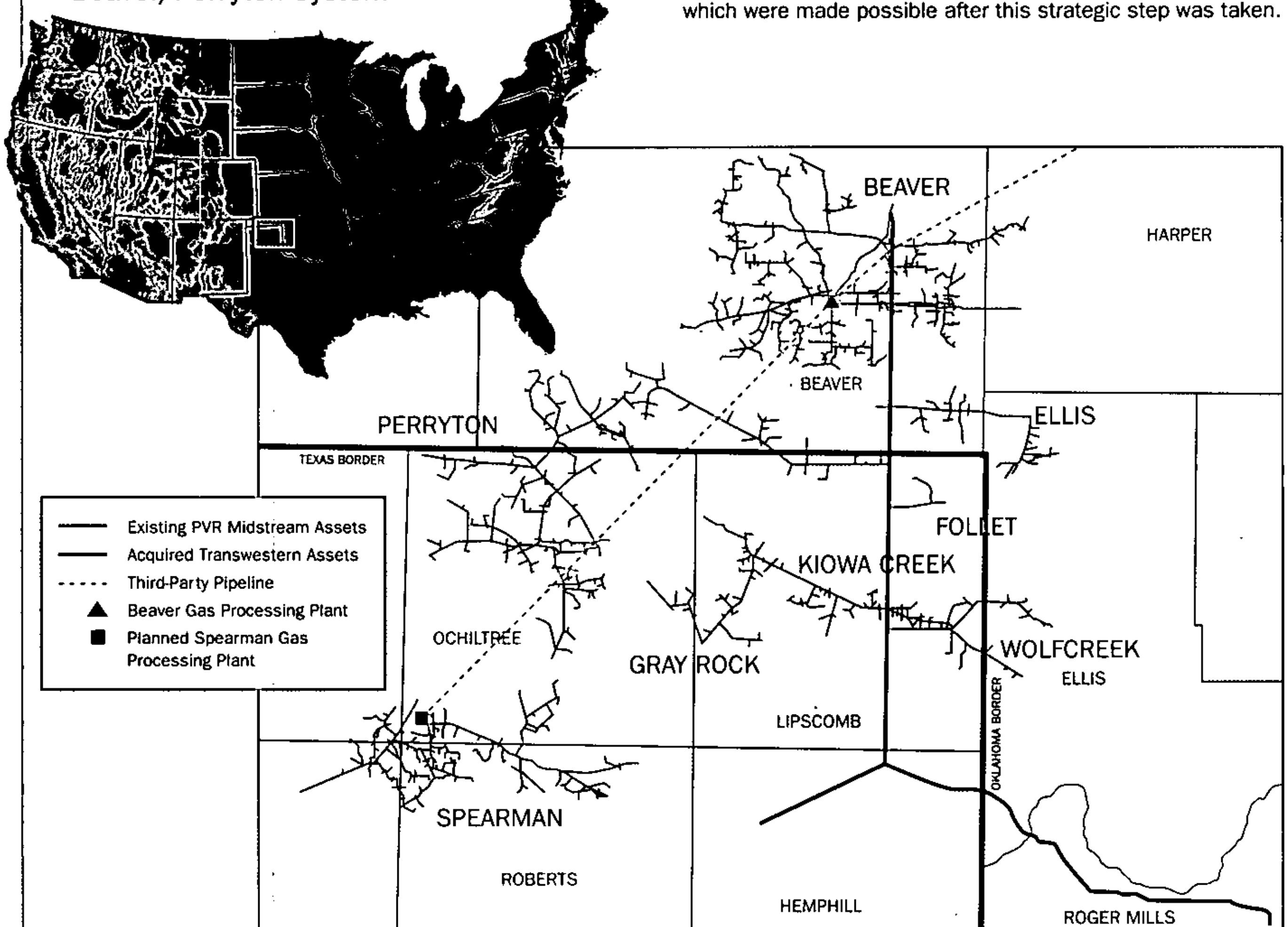
## Transwestern Acquisition

In June 2006, PVR Midstream acquired pipeline and compression facilities in the Texas panhandle and Oklahoma from Transwestern Pipeline Company, LLC for approximately $15 million. The acquired assets consisted of approximately 115 miles of 12-inch and 16-inch pipelines and 4,400 horsepower of compression and related facilities. The expansion is complementary to PVR Midstream's Beaver/Perryton System and the Beaver Gas Processing Plant, the largest contributor to PVR Midstream's inlet volumes and processing margins.

The acquisition immediately added 20 million cubic feet of natural gas per day to the Beaver/Perryton System and it provided significant operating efficiencies by allowing for the connection of certain previously non-contiguous PVR Midstream gathering systems directly to the Beaver plant. By being able to more fully load the Beaver plant with gas volumes, PVR Midstream was able to substantially increase utilization of and processing margins for the plant.

As a result of the acquisition and high frac spreads, PVR Midstream was able to deliver impressive results during 2006. PVR Midstream continues to pursue additional expansion opportunities in the Beaver/Perryton System which were made possible after this strategic step was taken.

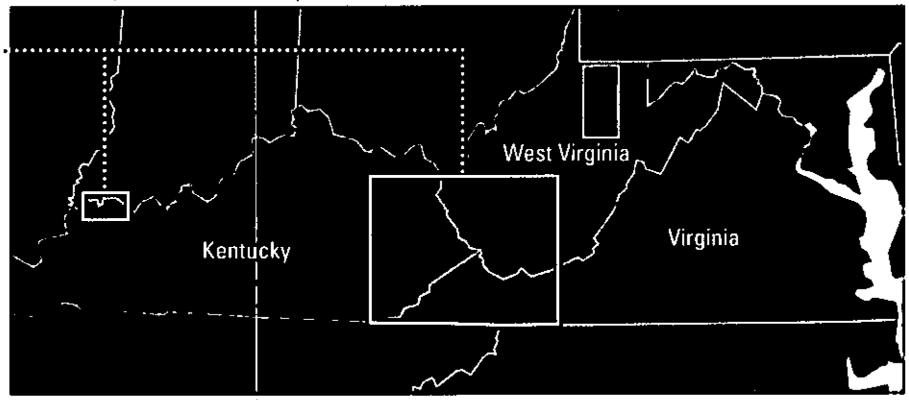
## Beaver/Perryton System



# Delivering on the Strategy

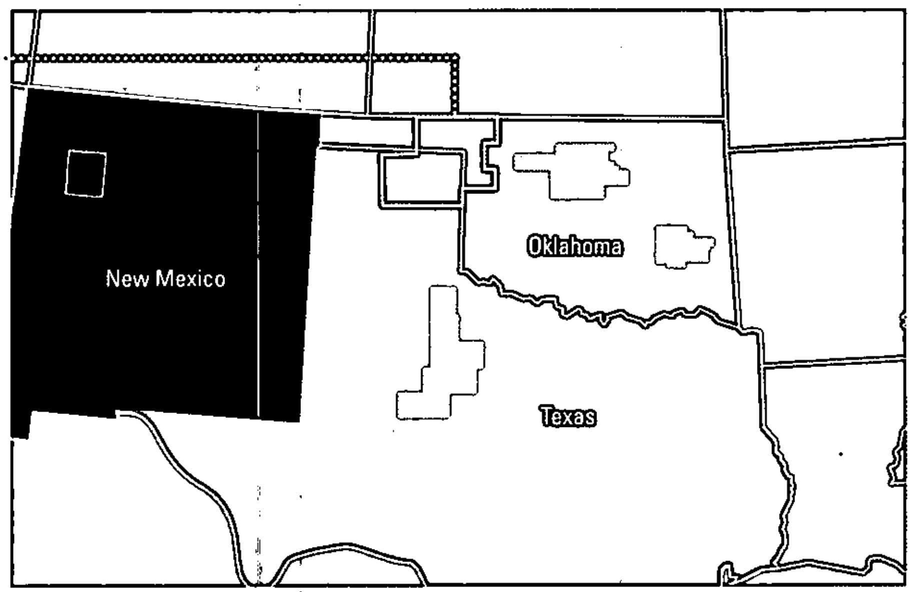
## 2006 Acquisition Summary

## Coal Reserve Acquisitions

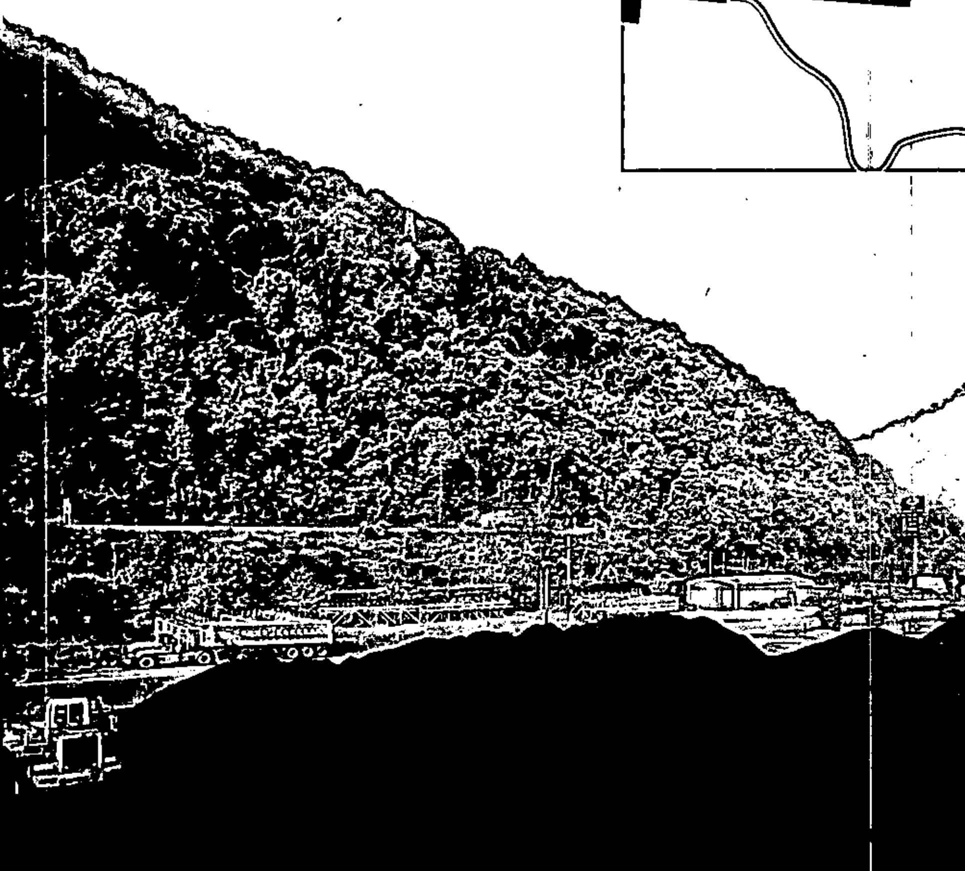


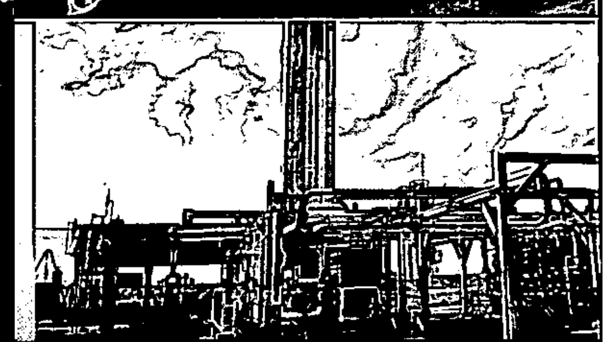

- $76 million for three acquisitions
- 96 million tons of reserves
- 2 central Appalachia acquisitions
- 1 Illinois Basin acquisition
- Growth in competitive central Appalachia core area and emerging Illinois Basin

## Transwestern Acquisition




- $15 million in June 2006
- 115 mile pipeline
- 4,400 HP and related facilities
- Added 20MMcf/d of dedicated volumes
- Ties together previously non-contiguous PVR gathering systems





# 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, 2006**

**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 the 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 $697,167,583 as of June 30, 2006 (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 the registrant's general partner, all affiliates of the registrant's general partner and all directors and executive officers of the registrant's general partner. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 28, 2007, 42,060,974 common units and 4,045,311 Class B units of the registrant were outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE:**
None

## PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

### Table of Contents

## Part I

### Item 1 *Business*

### General

Penn Virginia Resource Partners, L.P. (NYSE: PVR) is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation (NYSE: PVA), or Penn Virginia, in 2001 that is primarily engaged in the management of coal properties and the gathering and processing of natural gas in the United States. 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. In 2006, approximately 71%, or $73.4 million, of our operating income was attributable to our coal segment, and approximately 29%, or $29.4 million, of our operating income was attributable to our natural gas midstream segment. Unless the context requires otherwise, references to the "Partnership," "we," "us" or "our" in this Annual Report on Form 10-K refer Penn Virginia Resource Partners, L.P. and its subsidiaries.

*Coal Segment Overview*

Our coal segment includes management and leasing of coal properties and subsequent collection of royalties. Substantially all of our leases require the lessee to pay minimum rental payments to us 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 also 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, or Massey. In addition, we earn revenues from oil and gas royalty interests we own, from coal transportation, or wheelage, rights and from the sale of standing timber on our properties.

As of December 31, 2006, we owned or controlled approximately 765 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2006, approximately 87% of our proven and probable coal reserves was "steam" coal used primarily by electric generation utilities, and the remaining 13% was metallurgical coal used primarily by steel manufacturers. 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 2006, our lessees produced 32.8 million tons of coal from our properties and paid us coal royalty revenues of $98.2 million, for an average gross coal royalty per ton of $2.99. Approximately 84% of our coal royalty revenues in 2006 and 83% of our coal royalty revenues in 2005 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 that escalate annually.

Our management continues to focus on acquisitions that increase and diversify our sources of cash flow. During 2006, we increased our coal reserves by 96 million tons, or 14%, from our coal reserves as of December 31, 2005, by completing three coal reserve acquisitions with an aggregate purchase price of approximately $76 million. 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*

We own and operate midstream assets that include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing facilities located in Oklahoma and the panhandle of Texas, which have 160 million cubic feet per day (or 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. We also own 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 acquired our natural gas midstream assets through the acquisition of Cantera Gas Resources, LLC, or Cantera, in March 2005. We believe that this 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 these assets, we have expanded our natural gas midstream business by adding 181 miles of new gathering lines.

For the year ended December 31, 2006, inlet volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 56.0 billion cubic feet (or Bcf), or approximately 153 MMcfd. Two of our natural gas midstream customers, ConocoPhillips Company and BP Canada Energy Marketing Corp., accounted for 32% and 17% of our natural gas midstream revenues in 2006.

**Business Strategy**

Our primary business objective is to create sustainable, capital-efficient growth in distributable cash flow to maximize our cash distributions to our unitholders by expanding our coal property management and natural gas gathering and processing businesses through both internal growth and acquisitions. We have successfully grown our business through organic growth projects and acquisitions of coal properties and natural gas midstream assets. Since our initial public offering in October 2001, we have completed numerous accretive acquisitions with an aggregate purchase price of approximately $572 million. 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." We intend to continue to pursue the following business strategies:

- *Continue to grow coal reserve holdings through acquisitions and investments in our existing market areas, as well as strategically entering new markets.* During 2006, we increased our coal reserves by 96 million tons, or 14%, from our coal reserves as of December 31, 2005, by completing three coal reserve acquisitions in 2006 with an aggregate purchase price of approximately $76 million. While we continue to build upon our core holdings in Appalachia, we also continue to monitor coal opportunities in other areas. For example, in 2005 and 2006, we made investments in Illinois Basin coal reserves 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 not only higher sulfur Illinois Basin coal, but 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 typically involve long-lived, fee-based assets that generally produce steady and predictable cash flows and are therefore attractive to publicly traded limited partnerships. We own a number of such infrastructure facilities and intend to continue to look for growth opportunities in this area of operations. For example, we completed construction of a new preparation and loading facility in September 2006 on property we acquired in 2005. Operations at the facility commenced in the fourth quarter of 2006. Our joint venture with Massey is expected to provide other development opportunities for coal-related infrastructure projects.
- *Expand our midstream operations through acquisitions of new gathering and processing related assets and by adding new production to existing systems.* We continually seek new supplies of natural gas both to 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. In 2006, we added approximately 181 miles of new gathering lines, allowing us to connect 158 new wells to our systems.
- *Expand our midstream operations by utilizing the advantages of our relationship with Penn Virginia.* During 2006, we began marketing Penn Virginia's natural gas production in Louisiana, Oklahoma and Texas, 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 take advantage of our natural relationship with Penn Virginia in mutually beneficial ways.

## Contracts

*Coal Segment*

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), or 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.

*Natural Gas Midstream Segment*

Our natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. Our midstream business generates revenues primarily from gas purchase and processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. During the year ended December 31, 2006, our natural gas midstream business generated a majority of its gross margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and natural gas liquids (or NGLs): (i) percentage-of-proceeds and (ii) keep-whole arrangements. In 2006, approximately 50% of the volumes were processed under gas purchase/keep-whole contracts, 25% were processed under percentage of proceeds contracts, and 25% were processed under fee-based gathering contracts. A majority of the gas purchase/keep-whole and percentage of proceeds contracts include fee-based components such as gathering and compression charges. There is also a processing fee floor included in many of the gas purchase/keep-whole contracts that ensures a minimum processing margin should the actual margins fall below the floor.

*Gas purchase/keep-whole arrangements.* Under these arrangements, we generally purchase natural gas at the wellhead at either (i) a percentage discount to a specified index price, (ii) a specified index price less a fixed amount or (iii) a combination of (i) and (ii). We then gather the natural gas to one of our plants where it is processed to extract the entrained NGLs, which are then sold to third parties at market prices. We resell the remaining natural gas to third parties at an index price which typically corresponds to the specified purchase index. Because the extraction of the NGLs from the natural gas during processing reduces the British thermal unit (or BTU) content of the natural gas, we retain a reduced volume of gas to sell after processing. Accordingly, under these arrangements, our revenues and gross margins increase as the price of NGLs increases relative to the price of natural gas, and our revenues and gross margins decrease as the price of natural gas increases relative to the price of NGLs. We have generally been able to mitigate our exposure in the latter case by requiring the payment under many of our gas purchase/keep-whole arrangements of minimum processing charges which ensure that we receive a minimum amount of processing revenue. The gross margins that we realize under the arrangements described in clauses (i) and (iii) above also decrease in periods of low natural gas prices because these gross margins are based on a percentage of the index price.

*Percenage-of-proceeds arrangements.* Under percentage-of-proceeds arrangements, we generally gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds of those sales based on either an index price or the price actually received for the gas and NGLs. Under these types of arrangements, our revenues and gross margins increase as natural gas prices and NGL prices increase, and our revenues and gross margins decrease as natural gas prices and NGL prices decrease.

*Commodity Derivative Contracts.* We utilize swap derivative contracts to hedge against the variability in cash flows associated with forecasted natural gas midstream revenues and cost of gas purchased. While the use of derivative instruments limits the risk of adverse price movements, their use also may limit future revenues or cost savings from favorable price movements. With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. See Note 8 in the Notes to Consolidated Financial Statements for a description of our derivative program.

*Fee-based arrangements.* Under fee-based arrangements, we receive fees for gathering, compressing and/or processing natural gas. The revenue we earn from these arrangements is directly dependent on the volume of natural gas that flows through our systems and is independent of commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced due to the related reduction in drilling and development of new supply.

In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts were signed and customer requirements. The contract mix and, accordingly, exposure to natural gas and NGL prices, may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We are also engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into interstate and intrastate pipeline systems such as Enogex and ONEOK and at market hubs accessed by various interstate pipelines. The largest third-party customer is Chesapeake Energy Corp. with volumes contracted through 2007. Revenue from this business does not generate qualifying income for a publicly traded limited partnership, but we do not expect it to have an impact on our tax status, as it does not represent a significant percentage of our operating income. For the year ended December 31, 2006, this business generated $2.2 million in net revenue.

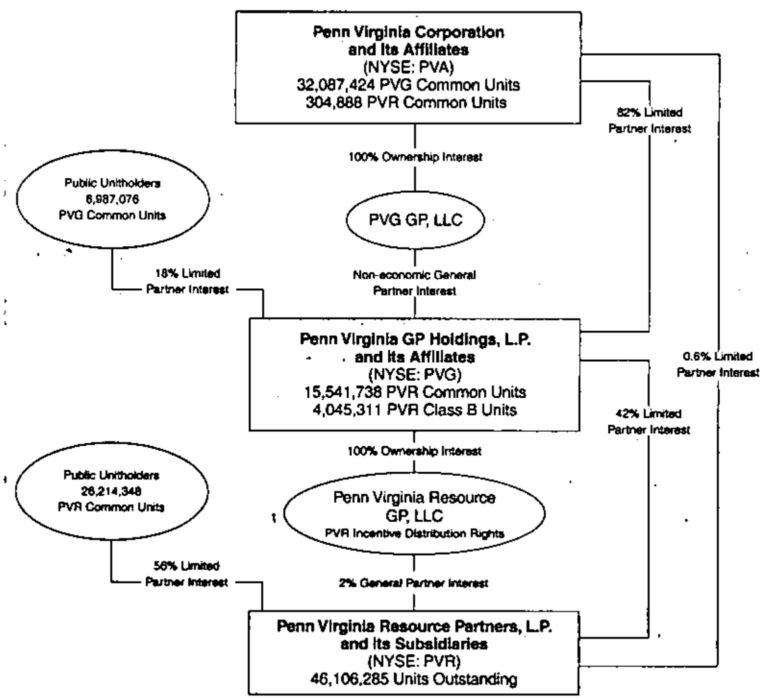
**Partnership Structure**

Penn Virginia, a publicly held energy company based in Radnor, Pennsylvania, 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 us 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 in October 2001. Penn Virginia continues to hold a significant interest in us through its indirect controlling interest in Penn Virginia GP Holdings, L.P. (NYSE: PVG), or PVG, a public traded Delaware limited partnership.

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, or the Operating Company. The following chart depicts our and our affiliates' current simplified organizational and ownership structure as of

December 31, 2006 (after giving effect to the exercise of the underwriters' option to purchase additional PVG common units granted in conection with PVG's initial public offering, or the PVG IPO):

- Penn Virginia Resource GP, LLC, our general partner and a wholly owned subsidiary of PVG, owns the 2% general partner interest and 100% of the incentive distribution rights in us;
- PVG owns 19,587,049 units of us, consisting of 15,541,738 common units and 4,045,311 Class B units, representing in the aggregate an approximately 42% limited partner interest in us;
- Penn Virginia and certain of its affiliates own 100% of the membership interests in PVG GP, LLC, PVG's general partner, which owns a non-economic interest in PVG, and 32,087,424 common units of PVG representing an approximately 82% limited partner interest in PVG;
- we own 100% of the membership interests in the Operating Company; and
- the Operating Company owns 100% of the membership interests in its subsidiaries, which include Fieldcrest LLC, K Rail LLC, Loadout LLC, PVR Midstream LLC, Suncrest LLC, Toney Fork LLC and Wise LLC.




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 distributed 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.

**Relationship with Penn Virginia Corporation**

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 us 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 is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Under an omnibus agreement between us, Penn Virginia and our general partner, Penn Virginia and its affiliates, including PVG and our general partner, are restricted in their ability to engage in any coal-related business. See Item 13, "Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons."

### Partnership Distributions

*Cash Distributions*

We paid cash distributions of $1.475 per common and subordinated unit during the year ended December 31, 2006. In the first quarter of 2007, we paid a quarterly distribution of $0.40 ($1.60 an annualized basis) per common and Class B unit with respect to the fourth quarter of 2006. For the remainder of 2007, we expect to make quarterly distributions of $0.40 ($1.60 an annualized basis) or more per common and Class B unit.

*Incentive Distribution Rights*

In accordance with our 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 $0.25 per unit ($1.00 per unit on an annualized basis). Our general partner currently holds 100% 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 our common, subordinated and Class B 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% to all unitholders, and 2% to our general partner, until each unitholder has received a total of $0.275 per unit for that quarter;
- Second, 85% to all unitholders, and 15% to our general partner, until each unitholder has received a total of $0.325 per unit for that quarter;
- Third, 75% to all unitholders, and 25% to our general partner, until each unitholder has received a total of $0.375 per unit for that quarter; and
- Thereafter, 50% to all unitholders and 50% to our general partner.

Our quarterly distribution rate has exceeded \$0.375 per unit since the distribution we paid in November 2006 with respect to the third quarter of 2006. Therefore, our general partner has received 50% of available cash in excess of \$0.375 per unit since then.

*Subordinated Units*

Until November 14, 2006, we had a separate class of subordinated units representing limited partner interests in us, and the rights of holders of subordinated units to participate in distributions to limited partners were subordinated to the rights of the holders of our common units. On November 14, 2006, all of our subordinated units converted into common units on a one-for-one basis and no subordinated units remain outstanding.

*Class B Units*

We currently have a separate class of units representing limited partner interests in us called Class B units. Each Class B unit is currently entitled to receive 100% of the quarterly cash distribution paid in respect of each common unit except that the Class B units are subordinated to the common units with respect to the payment of the minimum quarterly distribution and any arrearages with respect to the payment of the minimum quarterly distribution. We are required to submit to a vote of our unitholders, as promptly as practicable, a proposal to change the terms of the Class B units in order to provide that the Class B units will convert into common units, on a one-for-one basis, immediately upon the approval by our unitholders. Holders of the Class B units will not be entitled to vote upon the proposal to change the terms of the Class B units, but otherwise will vote with the common units as a single class on each matter with respect to which the common units are entitled to vote. If our unitholders do not approve the proposal to change the terms of the Class B units before December 8, 2007, then each Class B unit will be entitled to receive 115% of the quarterly amount we distribute in respect of each common unit on a subordinated basis to the payment of the minimum quarterly distribution on the common units.

Upon the dissolution and liquidation of us, each Class B unit is currently entitled to receive 100% of the amount distributed on each common unit, but only after each common unit has received an amount equal to its capital account, plus the minimum quarterly distribution for the quarter in which the liquidation occurs, plus any arrearages in the minimum quarterly distribution with respect to prior quarters. If, however, our unitholders do not approve the proposal to change the terms of the Class B units to make them convertible into common units, then each Class B unit will be entitled upon liquidation to receive 115% of the amount distributed in respect of each common unit, but only after each common unit has received an amount equal to its capital account, plus the minimum quarterly distribution for the quarter in which the liquidation occurs, plus any arrearages in the minimum quarterly distribution with respect to prior quarters on a subordinated basis to liquidating distributions on the common units.

**Limited Call Right**

If at any time our general partner and its affiliates own more than 80% of our outstanding common units, our general partner has the right, which it may assign in whole or in part to any of its affiliates or us, but not the obligation, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons as of a record date to be selected by our general partner, on at least ten but not more than 60 days notice, at a price not less than the then-current market price of the common units.

As a result of our general partner's right to purchase outstanding common units, a holder of common units may have his or her common units purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his or her units in the market.

As of February 28, 2007, PVG and its affiliates owned 15,541,738 common units, representing approximately 37% of our outstanding common units.

### Certain Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Penn Virginia and PVG), on the one hand, and us and our limited partners, on the other hand. Our general partner is controlled by PVG, which is in turn controlled by Penn Virginia. Accordingly, PVG (and Penn Virginia indirectly) has the ability to elect, remove and replace the directors and officers of our general partner. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners, Penn Virginia and PVG. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders.

Certain of the executive officers and non-independent directors of our general partner also serve as executive officers and directors of Penn Virginia or the general partner of PVG. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to Penn Virginia or PVG, on the one hand, and us, on the other hand, are in conflict.

### Limits on Fiduciary Responsibilities

Our partnership agreement limits the liability and reduces the fiduciary duties owed by our general partner to our unitholders. Our partnership agreement also restricts the remedies available to our 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, our 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 Revised Uniform Limited Partnership Act 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 Segment*

The coal industry is intensively competitive primarily as a result of the existence of numerous producers. Our lessees compete with both large and small 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.

*Natural Gas Midstream Segment*

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 do we.

## Government Regulation and Environmental Matters

The operations of our coal segment and natural gas midstream segment are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted.

*Coal Segment*

*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 (or PCBs). Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by 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 (or the 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 (or 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 (or 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 5% 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. Since the Kyoto Protocol became effective, there has been 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. This initiative aims to reduce emissions of carbon dioxide to levels roughly corresponding to average annual emissions between 2000 and 2004. Recently, in February 2007, Massachusetts and Rhode Island agreed to join this group. Maryland is required to join the group by June 2007, but implementing regulations have not been finalized as of yet.

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 (or 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 (or 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. Moreover, such individual permits are also subject to challenge. Alex Energy, Inc., a lessee of ours operating the Republic No. 2 Mine in Kanawha County, West Virginia, is currently a defendant in *Ohio Valley Environmental Coalition vs. U.S. Army Corps of Engineers*, a lawsuit in the Southern District of West Virginia in which environmental groups challenged the issuance of individual valley fill permits to multiple coal operators in the state. On June 13, 2006, the Corps of Engineers suspended the valley fill permits at issue in the case, including the permit under which our lessee operates. The court has since stayed all proceedings pending further action by the Corps on these permits. Although portions of the Republic No. 2 Mine continue to operate under separate authorizations, delays in securing additional permit authorization for the areas affected by the aforementioned permit withdrawal could 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 (or the 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. In January 2006, West Virginia passed a law imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. On March 7, 2006, New Mexico Governor Bill Richardson signed into law an expanded miner safety program including more stringent requirements for accident reporting and the installation of additional mine safety equipment at underground mines. Similarly, on April 27, 2006, Kentucky Governor Ernie Fletcher signed mine safety legislation that includes requirements for increased inspections of underground mines and additional mine safety equipment and authorizes the assessment of penalties of up to $5,000 per incident for violations of mine ventilation or roof control requirements.

On June 15, 2006, the President signed new mining safety legislation that mandates similar improvements in mine safety practices, increases civil and criminal penalties for non-compliance, requires the creation of additional mine rescue teams, and expands the scope of federal oversight, inspection and enforcement activities. Earlier, the federal Mine Safety Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the Federal Register on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect our lessees' coal production and could therefore have an adverse affect on our coal royalty revenues and our ability to make distributions to our unitholders.

*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 "—Coal Segment—Water Discharges."

*OSHA.* Our lessees and our business are subject to the requirements of the Occupational Safety and Health Act (or 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 Segment*

*General Regulation.* Our natural gas gathering facilities generally are exempt from the Federal Energy Regulatory Commission's (or the FERC) jurisdiction under the Natural Gas Act of 1938 (or 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.

For example, the FERC will assert jurisdiction over an affiliated gatherer that acts to benefit its pipeline affiliate in a manner that is contrary to the FERC's policies concerning jurisdictional services adopted pursuant to the NGA. In addition, natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our midstream operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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 (or 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 "—Coal Segment—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 "—Coal Segment—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 (or 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 "—Coal Segment—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 "—Coal Segment—OSHA."

**Employees and Labor Relations**

We do not have employees. To carry out our operations, our general partner and its affiliates employed 122 employees who directly supported our operations at December 31, 2006. Our general partner considers current employee relations to be favorable.

**Available Information**

Our internet address is www.pvresource.com. We make available free of charge on or through our 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 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 (or the Exchange Act) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. All references in this Annual Report on Form 10-K to the "NYSE" refer to the New York Stock Exchange, and all reference to the "SEC" refer to the Securities and Exchange Commission.

**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 Inherent in an Investment in Us**

*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 to our partners 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.

Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. 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.

*While we may incur debt to pay distributions to our unitholders, the agreements governing such debt may restrict or limit the distributions we can pay to our unitholders.*

While we are permitted by our partnership agreements to incur debt to pay distributions to our unitholders, our payment of principal and interest on such indebtedness will reduce our cash available for distribution on our unitholders. Furthermore, our debt agreements, including our revolving credit facility and senior notes, contain covenants limiting our ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions to its partners. They also contain covenants requiring us to maintain certain financial ratios. We are prohibited from making any distribution to our partners if such distribution would cause an event of default or otherwise violate a covenant under these agreements. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Debt," for more information about our revolving credit facility and senior notes.

*Our unitholders do not elect our general partner or vote on our general partner's directors. The owner of our general partner owns a sufficient number of units to allow it to prevent the removal of our general partner.*

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders do not have the ability to elect our general partner or the directors of our general partner and will have no right to elect our general partner or the directors of our general partner on an annual or other continuing basis in the future. The board of directors of our general partner, including our independent directors, is chosen by PVG, its sole member. Furthermore, if our public unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least two-thirds of the outstanding units. Because PVG owns more than one-third of our outstanding units, our general partner currently cannot be removed without its consent. As a result of these provisions, the price at which our common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

*Our general partner may cause us to issue additional common units or other equity securities without your approval, which would dilute your ownership interests.*

Our general partner may cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval. The issuance of additional common units or other equity securities of equal rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each common unit may decrease;
- the relative voting strength of each previously outstanding common unit may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of the common units may decline.

*The control of our general partner may be transferred to a third party who could replace our current management team, in either case, 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 our unitholders. Furthermore, PVG, the owner of our general partner, may transfer 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 and to control the decisions taken by the board of directors and officers.

*You may not have limited liability if a court finds that unitholder action constitutes control of our business.*

Under Delaware law, you could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under our partnership agreement constituted participation in the "control" of our business. Additionally, the limitations on the liability of holders of limited partner interests for the liabilities of a limited partnership have not been clearly established in many jurisdictions.

Furthermore, 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.

*Our partnership agreement restricts the rights of unitholders owning 20% or more of our units.*

Our unitholders' voting rights are restricted by the provision in our partnership agreement generally providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management. As a result, the price at which our common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

*We may issue additional limited partner interests or other equity securities, which may increase the risk that we will not have sufficient available cash to maintain or increase our cash distribution level.*

We have wide latitude to issue additional limited partner interests on the terms and conditions established by our general partner. If we have to pay distributions on additional limited partner interests, we may not be able to maintain or increase our quarterly cash distribution per unit.

**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.

*The coal mining operations of our lessees 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 that may increase our lessees' cost of mining and delay or halt production at particular mines for varying lengths of time and that are 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.

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 2006, five primary operators, each with multiple leases, accounted for 78% of our coal royalty revenues and 12% of our total consolidated 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 coal 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.

*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 production as of December 31, 2006. 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 coal reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our coal reserves.*

Our estimates of our coal 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;
- 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 coal 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 by us.

*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—Government Regulation and Environmental Matters—Coal Segment—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. See Item 1, "Business—Government Regulation and Environmental Matters—Coal Segment—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—Government Regulation and Environmental Matters—Coal Segment—Mining Permits and Approvals."

*Our lessees' mining operations are subject to extensive and costly laws and regulations, which 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—Government Regulation and Environmental Matters—Coal Segment."

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. See Item 1, "Business—Government Regulation and Environmental Matters—Coal Segment—Mine Health and Safety Laws," for a more detailed discussion of recently enacted legislation that addresses mine safety equipment, training and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect our lessees' coal production and could therefore have an adverse affect on our coal royalty revenues and our ability to make distributions.

### Risks Related to our Natural Gas Midstream Business

*The success of our natural gas 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 the level of drilling activity creating new gas supply near our gathering systems, our success in contracting for existing natural gas supplies that are not committed to other systems and our ability to expand and increase the capacity of our 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.

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.

*The profitability of our natural gas 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 natural gas commodity prices. During 2006, 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. See Item 1, "Business—Contracts—Natural Gas Midstream Segment."

Virtually all of the natural gas gathered on our Crescent System and Hamlin System is contracted under percentage-of-proceeds arrangements. The natural gas gathered on our 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.

*Acquisitions and expansions may affect our business by substantially increasing the level of its indebtedness and contingent liabilities and increasing the risks of being unable to effectively integrate these new operations.*

From time to time, we evaluate and acquire assets and businesses that we believe compliment our existing operations. We may encounter difficulties integrating these acquisitions with our existing businesses without a loss of employees or customers, a loss of revenues, an increase in operating or other costs or other difficulties. In addition, we may not be able to realize the operating efficiencies, competitive advantages, cost savings or other benefits expected from these acquisitions. Future acquisitions may require substantial capital or the incurrence of substantial indebtedness. As a result, our capitalization and results of operations may change significantly following an acquisition, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources. Future acquisitions might not generate increases in our pro forma available cash per unit, and may not increase cash distributions to our unitholders.

*Expanding our natural gas 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, the expansion of an existing pipeline through the addition of new pipe or compression 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 and our ability to make distributions.

*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 midstream customers. We depend on a limited number of customers for a significant portion of our midstream revenue. For 2006, two customers represented 49% of our total natural gas midstream revenues and 38% of our total consolidated revenues. Any nonpayment or nonperformance by our midstream 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.

*Natural gas 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. These 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. Our hedging transactions may not 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.

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 natural gas 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 natural gas midstream business.*

We own and operate an 11-mile interstate natural gas pipeline that, pursuant to the NGA, is subject to the jurisdiction of the FERC. The FERC has granted us 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 we 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. The FERC may revoke these waivers at any time.

Our natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but FERC regulation nevertheless could significantly change and affect our gathering business and the market for our services. For a more detailed discussion of how regulatory measures affect our natural gas gathering systems, see Item 1, "Business—Government Regulation and Environmental Matters—Natural Gas Midstream Segment."

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

*Our natural gas 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. See Item 1, "Business—Government Regulation and Environmental Matters—Natural Gas Midstream Segment."

## Risks Related to Conflicts of Interest

*Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner has limited fiduciary duties to us and our unitholders, which may permit it to favor its own interests to the detriment of us and our unitholders.*

Penn Virginia and its affiliates, including PVG, own an approximately 42% limited partner interest in us and own and control our general partner. Conflicts of interest may arise between our general partner and its affiliates (including Penn Virginia and PVG), on the one hand, and us and our unitholders, 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 our unitholders. These conflicts include, among others, the following situations:

- Our general partner is allowed to take into account the interests of parties other than us, such as Penn Virginia and PVG, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- Our general partner may limit its liability and reduce its fiduciary duties under our partnership agreement, while also restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing units, our unitholders 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 partnership securities and reserves, each of which can affect the amount of cash that is distributed to our unitholders.
- Our general partner controls the enforcement of obligations owed to us by it and its affiliates.
- Our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- Our partnership agreement does not restrict our general partner from causing us to pay it 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.

*The fiduciary duties of our general partner's officers and directors may conflict with those of PVG's general partner, and our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to us.*

Our general partner's officers and directors have fiduciary duties to manage our business in a manner beneficial to us and our unitholders and the owner of our general partner, PVG. However, half of our general partner's directors and three of its five officers are also directors or officers of PVG's general partner, which has fiduciary duties to manage the business of PVG in a manner beneficial to PVG and its unitholders, including Penn Virginia. Consequently, these directors and officers may encounter situations in which their fiduciary obligations to us on the one hand, and PVG, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

In addition, our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that might otherwise constitute a breach of our general partner's fiduciary duties owed to unitholders. By purchasing our units, you are treated as having consented to various actions contemplated in the partnership agreement and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law.

*We may face conflicts of interest in the allocation of administrative time among Penn Virginia's business, PVG's business and our business.*

Our general partner shares administrative personnel with Penn Virginia and PVG's general partner to operate Penn Virginia's business, PVG's business and our business. Our general partner's officers, who are also the officers of PVG's general partner and/or Penn Virginia, will have responsibility for overseeing the allocation of time spent by administrative personnel on our behalf and on behalf of PVG and/or Penn Virginia. These officers face conflicts regarding these time allocations that may adversely affect our results of operations, cash flows and financial condition. It is unlikely that these allocations will be the result of arms-length negotiations among Penn Virginia, PVG's general partner and our general partner.

*Our general partner has a call right that may require you to sell your common units at an undesirable time or price.*

If at any time more than 80% of our outstanding units are owned by our general partner and its affiliates, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the remaining units held by unaffiliated persons at a price equal to the greater of (x) the average of the daily closing prices of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (y) the highest price paid by our general partner or any of its affiliates for common units during the 90 day period preceding the date such notice is first mailed. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your common units. Affiliates of our general partner currently own approximately 43% of our outstanding units.

*Our general partner may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without prior approval of our unitholders.*

Our general partner may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without prior approval of our unitholders. If our general partner at any time decided to incur debt and secures its obligations or indebtedness by all or substantially all of our assets, and if our general partner is unable to satisfy such obligations or repay such indebtedness, the lenders could seek to foreclose on our assets. The lenders may also sell all or substantially all of our assets under such foreclosure or other realization upon those encumbrances without prior approval of our unitholders, which would adversely affect the price of our common units.

**Tax Risks to Our Common Unitholders**

*If we were to become subject to entity-level taxation for federal or state tax purposes, then our cash available for distribution to you would be substantially reduced.*

The anticipated after-tax economic benefit of an investment in our 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 Internal Revenue Service, or IRS, on this or any other matter affecting us.

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

Current law may change, causing 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. For example, we will be subject to a new entity-level tax or the portion of our income that is generated in Texas beginning in our tax year that ends December 31, 2007. Imposition of such tax on us by Texas or any other state, will reduce our cash available for distribution to you.

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 amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

*If the IRS contests the federal income tax positions that we take, it may adversely affect the market for our common units, and the costs of any contest will reduce cash available for distribution to our unitholders.*

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may disagree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

*You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.*

Because our unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash we distribute, 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, whether or not you receive 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 the taxation of your share of our taxable income.

*Tax gain or loss on disposition of our common units could be more or less than expected.*

If you sell your common units, you will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions to you in excess of the total net taxable income allocated to you, which decreased your tax basis in your common units, will, in effect, become taxable income to you if the common units are sold at a price greater than your tax basis in those common units, 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. In addition, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

*Tax-exempt entities 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, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. 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 such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States 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 1% 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 treat each purchaser of our common units as having the same tax benefits without regard to the common 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 may 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 our unitholders. 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 our common units or result in audits of and adjustments to our unitholders' tax returns.

*The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.*

We will be considered to have been terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A sale or exchange would occur, for example, if we sold our business or merged with another company, or if any of our unitholders, including Penn Virginia, PVG or any of their affiliates, sold or transferred their partnership interests in us. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

*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 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 now or in the future, 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 that may be required of you. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

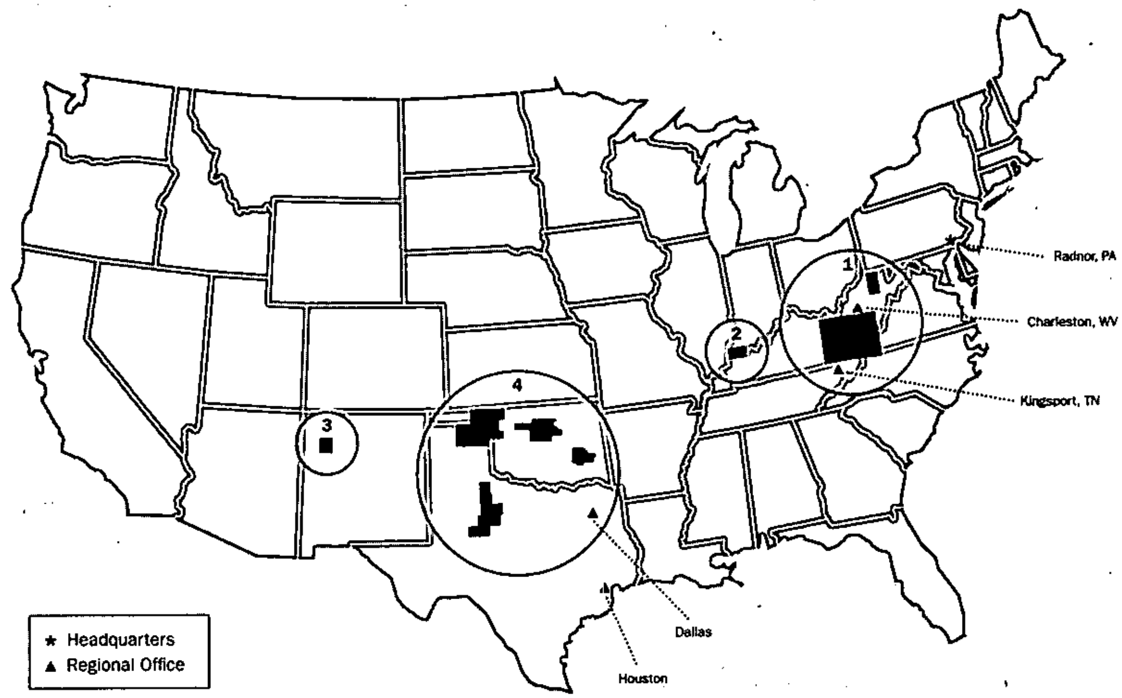
**Item 1B** ***Unresolved Staff Comments***

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, 2006.

## Item 2 *Properties*

### Title to Properties

The following maps show the general locations of our coal reserves and related infrastructure investments and our natural gas gathering and processing systems as of December 31, 2006:




**1. Coal Land Management**

**Central Appalachia**
559 million tons of high-quality coal reserves; coal services and infrastructure investments

**Northern Appalachia**
36 million tons of mid-to-high sulfur coal reserves

**2. Coal Land Management**

**Illinois Basin**
113 million tons of high sulfur coal reserves

**3. Coal Land Management**

**San Juan Basin**
58 million tons of midsulfur coal reserves

**4. Natural Gas Midstream**

**Mid-Continent Natural Gas Midstream Operations**

**Beaver/Perryton System**
Gathering pipelines – 1,377 miles
Processing plant – 100 MMcfd

**Crescent System**
Gathering pipelines – 1,679 miles
Processing plant – 40 MMcfd

**Hamlin System**
Gathering pipelines – 497 miles
Processing plant – 20 MMcfd

**Arkoma System**
Gathering pipelines – 78 miles

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, 2006, we owned or controlled approximately 765 million tons of proven and probable coal reserves located on approximately 379,000 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 located on the following properties:

- Central Appalachia Basin: properties, 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;
- Northern Appalachia Basin: properties located in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;
- San Juan Basin: properties located in McKinley County, New Mexico; and
- Illinois Basin: properties located in Henderson and Webster Counties, Kentucky.

Coal 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 coal reserves are classified as proven and probable reserves. Proven and probable reserves are defined as follows:

*Proven Reserves.* Proven reserves are reserves for which: (i) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; (ii) grade and/or quality are computed from the results of detailed sampling; and (iii) 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.

Coal 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. As of December 31, 2006, our lessees operated 29 surface mines and 39 underground mines. Approximately 73% of the coal produced from our properties in 2006 came from underground mines and 27% 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 electric utilities, also referred to as "steam" markets. 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 shows our most important coal producing seams by property:

| Area | Property | State | Producing Mine Types | Seam Name | Height Range (ft.) |
|---|---|---|---|---|---|
| Central Appalachia .... | Wise | Virginia, Kentucky | Surface, Underground | U. Parsons | 1.00 – 6.00 |
| | | | | Phillips | 1.50 – 6.00 |
| | | | | Low Splint | 1.00 – 5.50 |
| | | | | Taggart/Marker | 1.50 – 9.00 |
| | | | | U. Wilson | 1.50 – 5.50 |
| | | | | Kelly/Imboden | 1.00 – 7.50 |
| | Buchanan | Virginia | Surface, Underground | Hagy | 2.50 – 3.50 |
| | | | | Splashdam | 2.50 – 4.00 |
| | Wayland | Kentucky | Underground | U. Elkhorn No. 2 | 2.33 – 4.00 |
| | Coal River, Fields Creek | West Virginia | Surface, Underground | Stockton | 4.00 – 12.00 |
| | | | | Coalburg | 1.00 – 11.00 |
| | | | | Winifrede | 1.00 – 7.00 |
| | | | | Chilton | 1.00 – 4.00 |
| | | | | Cedar Grove | 1.00 – 5.50 |
| | | | | No. 2 Gas | 1.50 – 8.00 |
| | Toney Fork | West Virginia | Surface | Coalburg | 5.00 – 16.00 |
| | Spruce Laurel | West Virginia | Underground | Coalburg | 3.00 – 6.00 |
| | | | | Winifrede | 2.50 – 4.00 |
| | | | | Chilton | 2.50 – 4.00 |
| | | | | Alma | 2.50 – 7.00 |
| Northern Appalachia .... | Federal | West Virginia | Underground | Pittsburgh | 6.50 – 9.50 |
| | Upshur | West Virginia | Surface, Underground | Redstone | 3.00 – 6.50 |
| | | | | Pittsburgh | 2.00 – 9.00 |
| San Juan Basin .. | Lee Ranch | New Mexico | Surface | Cleary Group Seams | 8.00 – 16.00 |
| Illinois Basin .... | Green River | Kentucky | Surface, Underground | KY No. 9 | 3.00 – 5.00 |

The following tables set forth production data and reserve information with respect to each of our properties:

| Property | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| | (tons in millions) | | |
| Central Appalachia | 20.2 | 19.0 | 20.1 |
| Northern Appalachia | 5.0 | 5.0 | 5.6 |
| Illinois Basin | 2.5 | 1.4 | — |
| San Juan Basin | 5.1 | 4.8 | 5.5 |
| Total | 32.8 | 30.2 | 31.2 |

| Property | Proven and Probable Reserves at December 31, 2006: Underground | Surface | Total | Steam | Metallurgical | Total |
|---|---|---|---|---|---|---|
| | (tons in millions) | | | | | |
| Central Appalachia | 425.3 | 133.6 | 558.9 | 459.0 | 99.9 | 558.9 |
| Northern Appalachia | 33.8 | 2.2 | 36.0 | 36.0 | — | 36.0 |
| Illinois Basin | 99.6 | 13.0 | 112.6 | 112.6 | — | 112.6 |
| San Juan Basin | — | 57.9 | 57.9 | 57.9 | — | 57.9 |
| Total | 558.7 | 206.7 | 765.4 | 665.5 | 99.9 | 765.4 |

Of the approximately 765 million tons of proven and probable coal reserves to which we had rights as of December 31, 2006, we owned the mineral interests and the related surface rights to 461 million tons, or 60%, and we owned only the mineral interests to 164 million tons, or 22%. We lease the mineral rights to the remaining 140 million tons, or 18%, 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 leased reserves. Additionally, in some instances, we purchase surface rights or otherwise compensate surface right owners for mining activities on their properties. In 2006, our aggregate expenses to third-party surface and mineral owners were $6.9 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, 2006:

| Property | Owned | Leased | Total |
|---|---|---|---|
| | (tons in millions) | | |
| Central Appalachia | 422.7 | 136.2 | 558.9 |
| Northern Appalachia | 36.0 | — | 36.0 |
| Illinois Basin | 112.6 | — | 112.6 |
| San Juan Basin | 54.0 | 3.9 | 57.9 |
| Total | 625.3 | 140.1 | 765.4 |

Our coal reserve estimates are prepared from geological data assembled and analyzed by our general partner's or its affiliates' 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. Coal 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%, medium sulfur coal as coal with a sulfur content between 1.0% and 1.5% and high sulfur coal as coal with a sulfur content of greater than 1.5%.

Compliance coal is that portion of low sulfur coal that meets compliance standards for the Clean Air Act. As of December 31, 2006, approximately 27% of our reserves met compliance standards for the Clean Air Act and 42% were low sulfur. 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, 2006:

| | Sulfur Content | | | | | | Typical Clean Coal Quality | | |
|---|---|---|---|---|---|---|---|---|---|
| | Reserves as of December 31, 2006 | | | | | | Heat Content | | |
| **Property** | **Compliance (1)** | **Low Sulfur (2)** | **Medium Sulfur** | **High Sulfur** | **Sulfur Unclassified** | **Total** | **Btu per Pound (3)** | **Sulfur (%)** | **Ash (%)** |
| | (tons in millions) | | | | | | | | |
| Central Appalachia | 210.1 | 285.5 | 149.1 | 30.7 | 93.6 | 558.9 | 12,850 | 1.03 | 6.46 |
| Northern Appalachia | — | — | — | 36.0 | — | 36.0 | 12,900 | 2.58 | 8.80 |
| Illinois Basin | — | — | — | 112.6 | — | 112.6 | 11,034 | 2.96 | 8.32 |
| San Juan Basin | — | 34.6 | 18.6 | 4.7 | — | 57.9 | 9,200 | 0.89 | 17.80 |
| Total | 210.1 | 320.1 | 167.7 | 184.0 | 93.6 | 765.4 | | | |

(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 proven and probable coal reserves we lease to mine operators by property:

| | Proven and Probable Reserves As of December 31, 2006 | | |
|---|---|---|---|
| **Property** | **Total Controlled** | **Leased to Operators** | **Percentage Leased** |
| | (tons in millions) | | |
| Central Appalachia | 558.9 | 479.5 | 86% |
| Northern Appalachia | 36.0 | 35.2 | 98% |
| Illinois Basin | 112.6 | 40.5 | 36% |
| San Juan Basin | 57.9 | 57.9 | 100% |
| Total | 765.4 | 613.1 | 80% |

### Coal Preparation and Loading Facilities

We generate coal services 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 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. In September 2006, we completed construction of a new preparation and loading facility on property we acquired in 2005 in eastern Kentucky.

### Natural Gas Midstream Systems

Our midstream operations currently include three natural gas gathering and processing systems and a standalone natural gas gathering system, including: (i) the Beaver/Perryton gathering and processing facilities in the Texas/Oklahoma panhandle area, (ii) the Crescent gathering and processing facilities in central Oklahoma, (iii) the Hamlin gathering and processing facilities in west-central Texas and (iv) the Arkoma gathering system in eastern Oklahoma. These systems include approximately 3,631 miles of natural 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.

The following table sets forth information regarding our natural gas midstream assets:

| | | | | | Year Ended December 31, 2006 | |
|---|---|---|---|---|---|---|
| Asset | Type | Approximate Length (Miles) | Approximate Wells Connected | Current Processing Capacity (Mmcfd) | Average System Throughput (Mmcfd) | Utilization of Processing Capacity (%) |
| Beaver/Perryton System | Gathering pipelines and processing facility | 1,377 | 934 | 100 | 113.0 (1) | 100.0% |
| Crescent System | Gathering pipelines and processing facility | 1,679 | 888 | 40 | 18.4 | 46.0% |
| Hamlin System | Gathering pipelines and processing facility | 497 | 231 | 20 | 7.2 | 36.0% |
| Arkoma System | Gathering pipelines | 78 | 78 | — | 14.7 (2) | |
| | | 3,631 | 2,131 | 160 | 153.3 (3) | |

(1) Includes gas processed at other systems connected to the Beaver/Perryton System via the pipeline acquired in June 2006.
(2) Gathering only volumes.
(3) Total average system throughput would be 163 MMcfd if the acquisition of additional pipeline in June 2006 had occurred on January 1, 2006.

*Beaver/Perryton System*

*General.* The Beaver/Perryton System is a natural gas gathering system stretching over ten counties in the Anadarko Basin of the panhandle of Texas and Oklahoma. The system consists of approximately 1,377 miles of natural gas gathering pipelines, ranging in size from two to 16 inches in diameter, and the Beaver natural gas processing plant. Included in the system is an 11-mile, 10-inch diameter, FERC-jurisdictional residue line. Also included is the non-jurisdictional 115-mile pipeline that was recently acquired from Transwestern Pipeline Company, LLC and serves to connect a number of our gathering systems directly to the Beaver plant.

The Beaver/Perryton System is comprised of a number of major gathering systems and sixteen related compressor stations that gather natural gas, directly or indirectly, to the Beaver plant in Beaver County, Oklahoma. These include the Beaver, Perryton, Spearman, Wolf Creek/Kiowa Creek and Ellis systems. These gathering systems are located in Beaver, Ellis and Harper Counties in Oklahoma and Hansford, Hutchinson, Lipscomb, Ochiltree and Roberts Counties in Texas.

The Beaver natural gas processing plant has 100 MMcfd of inlet gas capacity. The plant is capable of relatively high ethane recovery, and is instrumented to allow for unattended operations 16 hours per day.

*Natural Gas Supply.* The supply in the Beaver/Perryton System comes from approximately 166 producers pursuant to 323 contracts. The average gas quality on the Beaver/Perryton System for 2006 was 3.6 gallons of NGLs per delivered Mcf.

*Markets for Sale of Natural Gas and NGLs.* The residue gas from the Beaver plant can be delivered into Northern Natural Gas, Southern Star Central Gas or ANR Pipeline Company pipelines for sale or transportation to market. The NGLs produced at the Beaver plant are delivered into Koch Hydrocarbon's pipeline system for transportation to and fractionation at Koch's Conway fractionator.

*Crescent System*

*General.* The Crescent System is a natural gas gathering system stretching over seven counties within central Oklahoma's Sooner Trend. The system consists of approximately 1,679 miles of natural gas gathering pipelines, ranging in size from two to 10 inches in diameter, and the Crescent gas processing plant located in Logan County, Oklahoma. Sixteen compressor stations are operating across the Crescent System.

The Crescent plant is a NGL recovery plant with current capacity of approximately 40 MMcfd. The Crescent facility also includes a gas engine-driven generator which is routinely operated, making the plant self-sufficient with respect to electric power. The cost of fuel (residue gas) for the generator is borne by the producers under the terms of their respective gas contracts.

*Natural Gas Supply.* The gas supply on the Crescent System is primarily gas associated with the production of oil or "casinghead gas" from the mature Sooner Trend. Wells in this region producing casinghead gas are generally characterized as low volume, long-lived producers of gas with large quantities of NGLs. The supply in the Crescent System comes from approximately 257 producers pursuant to 409 contracts. The average gas quality on the Crescent System for 2006 was 5.5 gallons of NGLs per delivered Mcf.

*Markets for Sale of Natural Gas and NGLs.* The Crescent plant's connection to the Enogex and ONEOK Gas Transportation pipelines for residue gas and the Koch Hydrocarbon pipeline for NGLs give the Crescent System access to a variety of market outlets.

*Hamlin System*

*General.* The Hamlin System is a natural gas gathering system stretching over eight counties in West Central Texas. The system consists of approximately 497 miles of natural gas gathering pipelines, ranging in size from two to 12 inches in diameter and with current capacity of approximately 20 MMcfd, and the Hamlin natural gas processing plant located in Fisher County, Texas. Eight compressor stations are operating across the system.

*Natural Gas Supply.* The gas on the Hamlin System is primarily gas associated with the production of oil or "casinghead gas." The supply on the Hamlin System comes from approximately 111 producers pursuant to 140 contracts. The average gas quality on the Hamlin System for 2006 was 9.8 gallons of NGLs per delivered Mcf.

*Markets for Sale of Natural Gas and NGLs.* The Hamlin System delivers the residue gas from the Hamlin System into the Enbridge or Atmos pipelines. NGLs from the Hamlin plant are tendered into a line operated by TEPPCO.

*Arkoma System*

*General.* The Arkoma System is a stand-alone gathering operation in southeastern Oklahoma's Arkoma Basin and is comprised of three separate gathering systems, two of which are 100% owned with the third system being 49% owned. We operate and maintain all three systems. The Arkoma System consists of a total of approximately 78 miles of natural gas gathering pipelines, ranging in size from three to 12 inches in diameter. Three compressor stations are operating across the Arkoma System.

*Natural Gas Supply.* The supply on the Arkoma System comes from approximately 16 producers pursuant to 29 contracts.

*Markets for Sale of Natural Gas and NGLs.* The Arkoma System lines deliver gas into the Ozark, Noram and NGPL pipelines.

**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—Government Regulation and Environmental Matters," 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 2006.

## 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 NYSE under the symbol "PVR." The high and low sales prices (composite transactions) for each fiscal quarter in 2006 and 2005 were as follows:

| Quarter Ended | High | Low |
|---|---|---|
| December 31, 2006 | $27.10 | $23.34 |
| September 30, 2006 | $28.10 | $23.01 |
| June 30, 2006 | $32.46 | $22.90 |
| March 31, 2006 | $31.03 | $26.27 |
| December 31, 2005 | $27.99 | $25.27 |
| September 30, 2005 | $27.10 | $23.95 |
| June 30, 2005 | $26.45 | $21.66 |
| March 31, 2005 | $28.58 | $23.84 |

We issued Class B units in December 2006, all of which are held by PVG. There is no established public trading market for our Class B units.

### Equity Holders

As of February 21, 2007, there were approximately 150 record holders and approximately 23,000 beneficial owners (held in street name) of our common units and one holder of our Class B units.

### Distributions

For the year ended December 31, 2006, we paid cash distributions of $1.475 per common and subordinated unit. For 2007, we expect to pay distributions of at least $1.60 per common and Class B unit.

The quarterly cash distributions paid in 2006 and 2005 were as follows:

| Period Covered by Distribution | Record Date | Payment Date | Amount Per Unit |
|---|---|---|---|
| Third quarter 2006 | November 3, 2006 | November 14, 2006 | $0.4000 |
| Second quarter 2006 | August 2, 2006 | August 12, 2006 | $0.3750 |
| First quarter 2006 | May 3, 2006 | May 13, 2006 | $0.3500 |
| Fourth quarter 2005 | February 4, 2005 | February 14, 2005 | $0.3500 |
| Third quarter 2005 | November 3, 2005 | November 14, 2005 | $0.3250 |
| Second quarter 2005 | August 2, 2005 | August 12, 2005 | $0.3250 |
| First quarter 2005 | May 3, 2005 | May 13, 2005 | $0.3100 |
| Fourth quarter 2004 | February 4, 2005 | February 14, 2005 | $0.2813 |

If cash distributions per unit exceed $0.275 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%. See Item 1, "Business—Partnership Distributions—Incentive Distribution Rights." On February 14, 2007, we paid a cash distribution with respect to the fourth quarter of 2006 of $0.40 per common and Class B unit, exceeding the $0.275 threshold.

There is no guarantee that we will pay quarterly cash distributions on our common units in any quarter, and we will be prohibited from making any distributions to our 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***

The following selected historical financial information was derived from our audited financial statements as of December 31, 2006, 2005, 2004, 2003 and 2002, and for each of the years then ended. The selected financial data should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data," and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 (1) | 2004 | 2003 | 2002 |
| | (in thousands, except per unit data) | | | | |
| Revenues | $517,891 | $446,348 | $ 75,630 | $ 55,642 | $ 38,608 |
| Expenses | $415,071 | $368,258 | $ 35,111 | $ 29,082 | $ 14,181 |
| Operating income | $102,820 | $ 78,090 | $ 40,519 | $ 26,560 | $ 24,427 |
| Net income | $ 73,928 | $ 51,161 | $ 34,315 | $ 22,690 | $ 24,686 |
| Net income per limited partner unit, basic and diluted | $ 1.56 | $ 1.22 | $ 0.93 | $ 0.62 | $ 0.79 |
| Total assets (2) | $714,023 | $657,879 | $284,435 | $259,892 | $266,575 |
| Long-term debt | $207,214 | $246,846 | $112,926 | $ 90,286 | $ 90,887 |
| Cash flows provided by operating activities | $107,344 | $ 93,712 | $ 54,782 | $ 41,077 | $ 30,342 |
| Distributions paid | $ 66,954 | $ 51,949 | $ 39,191 | $ 36,708 | $ 28,723 |
| Distributions paid per unit | $ 1.48 | $ 1.24 | $ 1.06 | $ 1.03 | $ 0.92 |

(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, (as defined in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments).

(2) 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. and its subsidiaries should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data." Our discussion and analysis include the following items:

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

## Overview of Business

We are a publicly traded Delaware limited partnership formed by Penn Virginia in 2001 that is principally engaged in the management of coal properties and the gathering and processing of natural gas in the United States. 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. In 2006, approximately 71%, or $73.4 million, of our operating income was attributable to our coal segment, and approximately 29%, or $29.4 million, of our operating income was attributable to our natural gas midstream segment.

### *Coal Segment*

As of December 31, 2006, we owned or controlled approximately 765 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2006, approximately 87% of our proven and probable coal reserves was "steam" coal used primarily by electric generation utilities, and the remaining 13% was metallurgical coal used primarily by steel manufacturers. 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 2006, our lessees produced 32.8 million tons of coal from our properties and paid us coal royalty revenues of $98.2 million, for an average gross coal royalty per ton of $2.99. Approximately 84% of our coal royalty revenues in 2006 and 83% of our coal royalty revenues in 2005 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 that escalate annually.

Coal prices, especially in Central Appalachia where the majority of our coal is produced, increased significantly from the beginning of 2004 through most of 2006. The price increase stems from several causes, including increased electricity demand and decreasing coal production in Central Appalachia.

Substantially all of our leases require the lessee to pay minimum rental payments to us 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 also 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. In addition, we earn revenues from oil and gas royalty interests we own, from wheelage rights and from the sale of standing timber on our properties. During 2006, five lessees accounted for 78% of our coal royalty revenues.

Our management continues to focus on acquisitions that increase and diversify our sources of cash flow. During 2006, we increased our coal reserves by 96 million tons, or 14%, from our coal reserves as of December 31, 2005, by completing three coal reserve acquisitions in 2006 with an aggregate purchase price of approximately $76 million. For a more detailed discussion of our acquisitions, see "—Acquisitions and Investments."

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 have or 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. See Item 1A, "Risk Factors."

### *Natural Gas Midstream Segment*

We own and operate midstream assets that include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing facilities located in Oklahoma and the panhandle of Texas, which have

160 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. We also own 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 acquired our natural gas midstream assets through the acquisition of Cantera in March 2005. We believe that this 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 these assets, we have expanded our natural gas midstream business by adding 181 miles of new gathering lines.

For year ended December 31, 2006, inlet volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 56.0 Bcf, or approximately 153 MMcfd. Two of our natural gas midstream customers, ConocoPhillips Company and BP Canada Energy Marketing Corp., accounted for 32% and 17% of our natural gas midstream revenues in 2006.

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.

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 generally correlated with changes in the price of crude oil. NGL and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market uncertainty.

*Unit Split*

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

*Conclusion of Subordination Period*

The subordination period with respect to 7,649,880 of our subordinated units expired on October 1, 2006. As a result, all of the outstanding subordinated units converted into common units on a one-for-one basis in accordance with their terms when we paid our third quarter distribution on November 14, 2006.

**Acquisitions and Investments**

*Coal Segment*

*LG&E Acquisition.* In December 2006, we acquired ownership and lease rights to approximately 22 million tons of coal reserves. The reserves are located in Henderson County, Kentucky. The purchase price was $9.3 million and was funded with cash.

*Coal Infrastructure Construction.* In September 2006, we completed construction of a new 600-ton per hour coal processing plant and rail loading facility for one of our lessees located in Knott County in eastern Kentucky. The facility began operations in October 2006. Since acquiring fee ownership and lease rights to the property's coal reserves in July 2005, we made cumulative capital expenditures of $15.4 million related to the construction of the facility.

*Huff Creek Acquisition.* In May 2006, we acquired the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Boone, Logan and Wyoming Counties, West Virginia. The purchase price was $65.0 million and was funded with long-term debt under our revolving credit facility.

*Green River Acquisition.* In July 2005, we also acquired fee ownership of approximately 94 million tons of coal reserves located along the Green River in the western Kentucky portion of the Illinois Basin for $62.4 million in cash and the assumption of $3.3 million of deferred income. This coal reserve acquisition was our first in the Illinois Basin and was funded with long-term debt under our revolving credit facility. Currently, approximately 41 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.

*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 reserves are located in the eastern Kentucky portion of Central Appalachia. The acquisition was funded with $4.0 million of cash and our issuance to the seller of approximately 209,000 common units.

*Alloy Acquisition.* In April 2005, we acquired fee ownership of approximately 16 million tons of coal reserves for $15.0 million in cash. The reserves, located near Alloy, West Virginia 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 acquisition was funded with long-term debt under our revolving credit facility.

*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 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 contained approximately 2.8 billion cubic feet equivalent (or Bcfe) of net proved oil and gas reserves with net production of approximately 0.2 Bcfe on an annualized basis.

*Coal Handling Joint Venture.* In July 2004, we acquired from affiliates of Massey a 50% 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 $1.3 million in 2006, $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 $2.7 million in 2006, $2.3 million in 2005 and $1.0 million in 2004.

*Natural Gas Midstream Segment*

*Transwestern Acquisition.* In June 2006, we completed the acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma. These assets are contiguous to our Beaver/Perryton System. We paid $14.7 million in cash for the acquisition. Subsequently, we borrowed $14.7 million under our revolving credit facility to replenish the cash used for the acquisition.

*Cantera Acquisition.* In March 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 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.

**Current Performance**

Operating income for 2006 was $102.8 million. The coal segment contributed $73.4 million, or 71%, to operating income, and the natural gas midstream segment contributed $29.4 million, or 29%. The following table presents a summary of certain financial information relating to our segments (in thousands):

| | Coal | Natural Gas Midstream (1) | Consolidated |
|---|---|---|---|
| **For the Year Ended December 31, 2006:** | | | |
| Revenues | $112,981 | $404,910 | $517,891 |
| Cost of midstream gas purchased | — | 334,594 | 334,594 |
| Operating costs and expenses | 19,138 | 23,846 | 42,984 |
| Depreciation, depletion and amortization | 20,399 | 17,094 | 37,493 |
| Operating income | $ 73,444 | $ 29,376 | $102,820 |
| **For the Year Ended December 31, 2005:** | | | |
| Revenues | $ 95,755 | $350,593 | $446,348 |
| Cost of midstream gas purchased | — | 303,912 | 303,912 |
| Operating costs and expenses | 16,121 | 17,597 | 33,718 |
| Depreciation, depletion and amortization | 17,890 | 12,738 | 30,628 |
| Operating income | $ 61,744 | $ 16,346 | $ 78,090 |
| **For the Year Ended December 31, 2004:** | | | |
| Revenues | $ 75,630 | $ — | $ 75,630 |
| Cost of midstream gas purchased | — | — | — |
| Operating costs and expenses | 16,479 | — | 16,479 |
| Depreciation, depletion and amortization | 18,632 | — | 18,632 |
| Operating income | $ 40,519 | $ — | $ 40,519 |

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

*Coal Segment*

In 2006, coal royalty revenues increased 19%, or $15.5 million, over 2005 due to acquisitions, more coal being mined by our lessees and increasing coal prices. Tons produced by our lessees increased from 30.2 million tons in 2005 to 32.8 million tons in 2006, and our average gross royalties per ton increased from $2.74 in 2005 to $2.99 in 2006. Generally, as coal prices change, our average royalties per ton also change because the majority of our lessees pay royalties based on the gross sales prices of the coal mined. Most of our coal is sold by our lessees under contracts with a duration of one year or more; therefore, changes to our average royalties occur as our lessees' contracts are renegotiated. The Illinois Basin coal reserves that we acquired in July 2005 resulted in $4.8 million of coal royalty revenues in 2006 compared to $2.7 million in 2005. The Huff Creek Acquisition in May 2006 resulted in $4.8 million of coal royalty revenues in 2006.

Coal services revenues increased to $5.9 million in 2006 from $5.2 million in 2005. In September 2006, we completed construction of a coal service facility in Knott County, Kentucky, which began operations in October 2006. The new facility contributed $0.2 million to coal services revenues in 2006. We believe that these types of fee-based infrastructure assets provide good investment and cash flow opportunities, and we continue to look for additional investments of this type, as well as other primarily fee-based assets.

The following table summarizes coal production and coal royalty revenues by property:

| Property | Coal Production Year Ended December 31, 2006 | 2005 | Coal Royalty Revenues Year Ended December 31, 2006 | 2005 |
|---|---|---|---|---|
| | (tons in thousands) | | (in thousands) | |
| Central Appalachia | 20,156 | 18,996 | $76,542 | $64,645 |
| Northern Appalachia | 5,009 | 4,958 | 7,314 | 6,973 |
| Illinois Basin | 2,540 | 1,449 | 4,768 | 2,709 |
| San Juan Basin | 5,073 | 4,824 | 9,539 | 8,398 |
| Total | 32,778 | 30,227 | $98,163 | $82,725 |

*Natural Gas Midstream Segment*

The gross processing margin for our natural gas midstream operations increased from $44.7 million in 2005 to $68.1 million in 2006. This increase was due primarily to higher NGL and condensate prices and the contribution of the Transwestern Acquisition. Inlet volumes at our gas processing plants and gathering systems were 153 MMcfd in 2006, an increase over 127 MMcfd in 2005, primarily due to additional well connections in the area. Our midstream business generates revenues primarily from gas purchase and processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. During the year ended December 31, 2006, our natural gas midstream business generated a majority of its gross margin from contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business—Contracts—Natural Gas Midstream Segment," for a discussion of the types of contracts utilized by the natural gas midstream segment. As part of our risk management strategy, we use derivative financial instruments to economically hedge NGLs sold and natural gas purchased. See the tables in "—Results of Operations—Natural Gas Midstream Segment—Expenses" for the effects of our derivative program on gross processing margin.

Our natural gas midstream assets are primarily located in the Mid-Continent area of Oklahoma and the panhandle of Texas. The following table sets forth information regarding our natural gas midstream assets as of December 31, 2006:

| Asset | Type | Approximate Length (Miles) | Approximate Wells Connected | Current Processing Capacity (Mmcfd) | Year Ended December 31, 2006 Average System Throughput (Mmcfd) | Utilization of Processing Capacity (%) |
|---|---|---|---|---|---|---|
| Beaver/Perryton System | Gathering pipelines and processing facility | 1,377 | 934 | 100 | 113.0 (1) | 100.0% |
| Crescent System | Gathering pipelines and processing facility | 1,679 | 888 | 40 | 18.4 | 46.0% |
| Hamlin System | Gathering pipelines and processing facility | 497 | 231 | 20 | 7.2 | 36.0% |
| Arkoma System | Gathering pipelines | 78 | 78 | — | 14.7 (2) | |
| | | 3,631 | 2,131 | 160 | 153.3 (3) | |

(1) Includes gas processed at other systems connected to the Beaver/Perryton System via the pipeline acquired in June 2006.

(2) Gathering only volumes.

(3) Total average system throughput would be 163 MMcfd if the acquisition of additional pipeline in June 2006 had occurred on January 1, 2006.

**Summary of 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.

*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.

*Derivative Activities*

We historically have entered into derivative financial instruments that would qualify for hedge accounting under Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Hedge accounting affects the timing of revenue recognition and cost of midstream gas purchased in our consolidated statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the hedged transaction settles. Because during the first quarter of 2006 our natural gas derivatives and a large portion of our NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). Because we no longer use hedge accounting for our commodity derivatives, we could experience significant changes in the estimate of derivative gain or loss recognized in revenues and cost of midstream gas purchased due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

*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 coal 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.

*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 2006, no goodwill impairment was recognized in 2006.

*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 are reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

## Liquidity and Capital Resources

We generally satisfy our working capital requirements and funds our capital expenditures and debt service obligations from cash generated from our operations and borrowings under our revolving credit facility. We believe that the cash generated from our operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. Our ability to satisfy our obligations and planned expenditures will depend upon our future operating performance, which will be affected by, among other things, prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond our control.

PVG completed its initial public offering in December 2006 and used substantially all of the resulting proceeds to purchase newly issued common and Class B units from us. We then used the proceeds from the purchase to repay $114.6 million of debt outstanding under our revolving credit facility.

Summarized cash flow statements for 2006 and 2005, consolidating our segments, are set forth below (in thousands):

| For the year ended December 31, 2006 | Coal | Natural Gas Midstream | Consolidated |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income contribution | $ 55,015 | $ 18,913 | $ 73,928 |
| Adjustments to reconcile net income to net cash provided by operating activities (summarized) | 22,478 | 10,878 | 33,356 |
| Net change in operating assets and liabilities | 1,450 | (1,390) | 60 |
| Net cash provided by operating activities | $ 78,943 | $ 28,401 | 107,344 |
| Net cash used in investing activities | $(92,692) | $(36,984) | (129,676) |
| Net cash provided by financing activities | | | 10,579 |
| Net decrease in cash and cash equivalents | | | $ (11,753) |

| For the year ended December 31, 2005 | Coal | Natural Gas Midstream | Consolidated |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income contribution | $ 48,379 | $ 2,782 | $ 51,161 |
| Adjustments to reconcile net income to net cash provided by operating activities (summarized) | 20,887 | 21,029 | 41,916 |
| Net change in operating assets and liabilities | 2,333 | (1,698) | 635 |
| Net cash provided by operating activities | $ 71,599 | $ 22,113 | 93,712 |
| Net cash used in investing activities | $(97,109) | $(206,512) | (303,621) |
| Net cash provided by financing activities | | | 212,105 |
| Net increase in cash and cash equivalents | | | $ 2,196 |

*Cash Flows*

Cash provided by operating activities increased $13.6 million, or 15%, to $107.3 million for the year ended December 31, 2006 from $93.7 million for 2005. The overall increase in cash provided by operating activities in 2006 compared to 2005 was primarily attributable to higher average gross coal royalties per ton and cash flows from our natural gas midstream business, which was acquired in March 2005, partially offset by increased cash outflows for derivative settlements. Cash provided by operating activities increased $38.9 million, or 71%, to $93.7 million for the year ended December 31, 2005 from $54.8 million for 2004. The overall increase in cash provided by operating activities in 2005 compared to 2004 was primarily attributable to higher average gross coal royalties per ton and cash flows from our newly acquired natural gas midstream business.

We made cash investments in 2006 primarily for coal reserve acquisitions, coal loadout facility construction and natural gas midstream acquisitions and gathering system expansions. We made cash investments in 2005 primarily for the acquisition of our natural gas midstream business 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.

Capital expenditures, excluding noncash items, for each of the three years ended December 31, 2006 were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (in thousands) | |
| Coal | | | |
| Acquisitions (1) | $ 75,182 | $ 92,093 | $28,675 |
| Expansion capital expenditures | 15,103 | 5,657 | 783 |
| Other property and equipment expenditures | 100 | 351 | 72 |
| Total | 90,385 | 98,101 | 29,530 |
| Natural gas midstream | | | |
| Acquisitions, net of cash acquired | 14,626 | 199,223 | — |
| Expansion capital expenditures | 15,394 | 3,324 | — |
| Other property and equipment expenditures | 9,414 | 4,264 | — |
| Total | 39,434 | 206,811 | — |
| Total capital expenditures | $129,819 | $304,912 | $29,530 |

(1) Amount in 2006 excludes acquisition of assets and liabilities other than property or equipment of $1.2 million. Amount in 2005 excludes 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 excludes the noncash portion of the Green River Acquisition, in which we assumed $3.3 million of deferred income. Amount in 2004 excludes noncash expenditures of $1.1 million to acquire additional reserves on our Northern Appalachia properties in exchange for equity issued in the form of common and Class B units.

We funded capital expenditures in 2006, including three acquisitions and coal infrastructure construction, with cash flows from operations, borrowings under our revolving credit facility, proceeds from the sale of common and Class B units to PVG and a contribution from our general partner to maintain its 2% general partner interest in us. To finance our 2005 acquisitions, we borrowed $137.2 million, net of repayments, received proceeds of $126.4 million from our secondary public offering of common units 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. Distributions to partners increased to $67.0 million in 2006 from $51.9 million in 2005 and $39.2 million in 2004 because we increased the quarterly distribution per unit.

*Long-Term Debt*

As of December 31, 2006, we had outstanding borrowings of $218.0 million, consisting of $143.2 million borrowed under our revolving credit facility and $74.8 million of senior unsecured notes (or the Notes). The current portion of the Notes as of December 31, 2006 was $10.8 million.

*Revolving Credit Facility.* As of December 31, 2006, we had $143.2 million outstanding under our unsecured $300 million revolving credit facility (or the Revolver) that matures in December 2011. We used the proceeds from the sale of common units and Class B units to PVG in December 2006 to pay down $114.6 million of the Revolver. The Revolver is available to us for general 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, 2006. In 2006, we incurred commitment fees of $0.4 million on the unused portion of the Revolver. We have a one-time option to expand the Revolver by $150 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders. The interest rate under the Revolver fluctuates based on our ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if we select the base rate borrowing option under the Revolver or at a rate derived from the London Inter Bank Offering Rate (or LIBOR) plus an applicable margin ranging from 0.75% to 1.75% if we select the LIBOR-based borrowing option.

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 $257.0 million as of December 31, 2006. At the current $300 million limit on the Revolver, and given our outstanding balance of $143.2 million, net of $1.6 million of letters of credit, we could borrow up to $155.2 million without exercising our one-time option to expand the Revolver. In order to utilize the full extent of the $257.0 million borrowing capacity, we would need to exercise our one-time option to expand the Revolver by $150 million. The Revolver prohibits us from making distributions to our partners 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, 2006, we were in compliance with all of our covenants under the Revolver.

*Senior Unsecured Notes.* As of December 31, 2006, we owed $74.8 million under the Notes. The Notes bear interest at a fixed rate of 6.02% and mature in March 2013, with semi-annual principal and interest payments.

The Notes are equal in right of payment with all of our other unsecured indebtedness, including the Revolver. The Notes require us to obtain an annual confirmation of our credit rating, with a 1.00% increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. In March 2006, our investment grade credit rating was confirmed by Dominion Bond Rating Services. The Notes contain various covenants similar to those contained in the Revolver. As of December 31, 2006, we were in compliance with all of our covenants under the Notes.

*Interest Rate Swap.* In September 2005, we entered into interest rate swap agreements (or the Revolver Swaps) with notional amounts totaling $60 million to establish fixed rates on the LIBOR-based portion of the outstanding balance of the Revolver until March 2010. We pay a weighted average fixed rate of 4.22% 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 Swaps 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 0.75% in effect as of December 31, 2006, the total interest rate on the $60 million portion of Revolver borrowings covered by the Revolver Swaps was 4.97% at December 31, 2006.

*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.

In 2007, we anticipate making capital expenditures, excluding acquisitions, of approximately $3.6 million to $4.7 million for coal services projects and other property and equipment and approximately $47 million to $52 million for natural gas midstream projects. We intend to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under the Revolver, under which we had $155.2 million of borrowing capacity as of December 31, 2006. 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. Funding sources for future acquisitions are dependent on the size of any such acquisitions and are expected to be provided by a combination of cash flows provided by operating activities and borrowings, and potentially with the proceeds from the issuance of additional equity.

## Contractual Obligations

Our contractual obligations as of December 31, 2006 are summarized in the following table:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1-3 Years | 4-5 Years | Thereafter |
| | | | (in thousands) | | |
| Revolving credit facility | $143,200 | $ — | $ — | $143,200 | $ — |
| Senior unsecured notes | 75,400 | 11,000 | 26,800 | 24,200 | 13,400 |
| Rental commitments (1) | 5,208 | 1,329 | 2,069 | 1,810 | — |
| Total contractual obligations (2) | $223,808 | $12,329 | $28,869 | $169,210 | $13,400 |

(1) Our rental commitments primarily relate to equipment, building and 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. See Item 1A, "Risk Factors." We believe that the future rental commitments cannot be estimated with certainty; however, based on current knowledge and historical trends, we believe that we will incur approximately $0.9 million in rental commitments annually until the reserves have been exhausted.
(2) The total contractual obligations do not include reimbursement to our general partner. Our general partner is entitled to receive reimbursement of direct and indirect expenses incurred on our behalf until we are dissolved.

We do not have employment agreements with executive officers and do not have any other employees. Our compensation obligations with respect to our executive officers can be significantly different from one year to another and is based on variables such as our performance for the given year. For more a more detailed discussion on our executive compensation, see Item 11, "Executive Compensation."

### Off-Balance Sheet Arrangements

At December 31, 2006, 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

The following table sets forth a summary of certain financial data for the periods indicated:

*Selected Financial Data—Consolidated*

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (in thousands except per unit data) | | |
| Revenues | $517,891 | $446,348 | $75,630 |
| Expenses | $415,071 | $368,258 | $35,111 |
| Operating income | $102,820 | $ 78,090 | $40,519 |
| Net income | $ 73,928 | $ 51,161 | $34,315 |
| Net income per limited partner unit, basic and diluted | $ 1.56 | $ 1.22 | $ 0.93 |
| Cash flows provided by operating activities | $107,344 | $ 93,712 | $54,782 |

The increase in 2006 net income compared to 2005 net income was primarily attributable to a $24.7 million increase in operating income and a $2.8 million decrease in derivative losses in our natural gas midstream segment, partially offset by a $4.8 million increase in interest expense. Operating income increased in 2006 primarily due to increased coal royalty revenues resulting from higher commodity prices and related services income and increased gross margin from our natural gas midstream business, which was acquired in March 2005.

The increase in 2005 net income compared to 2004 net income was primarily attributable to a $37.6 million increase in operating income, which was partially offset by a $14.0 million unrealized loss on derivatives in PVR's 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 business, which was acquired in March 2005.

*Coal Segment*

***Year Ended December 31, 2006 Compared With Year Ended December 31, 2005***

The following table sets forth a summary of certain financial and other data for our coal segment and the percentage change for the periods indicated:

| | Year Ended December 31, 2006 | Year Ended December 31, 2005 | % Change |
|---|---|---|---|
| | (in thousands, except as noted) | | |
| ***Financial Highlights*** | | | |
| **Revenues** | | | |
| Coal royalties | $ 98,163 | $82,725 | 19% |
| Coal services | 5,864 | 5,230 | 12% |
| Other | 8,954 | 7,800 | 15% |
| Total revenues | 112,981 | 95,755 | 18% |
| **Expenses** | | | |
| Operating | 8,600 | 5,755 | 49% |
| Taxes other than income | 934 | 1,129 | (17)% |
| General and administrative | 9,604 | 9,237 | 4% |
| Depreciation, depletion and amortization | 20,399 | 17,890 | 14% |
| Total expenses | 39,537 | 34,011 | 16% |
| **Operating income** | $ 73,444 | $61,744 | 19% |
| ***Operating Statistics*** | | | |
| Royalty coal tons produced by lessees (tons in millions) | 32,778 | 30,227 | 8% |
| Average royalty per ton ($/ton) | $ 2.99 | $ 2.74 | 9% |

*Revenues.* Coal royalty revenues increased to $98.2 million in 2006 from 82.7 million in 2005, or 19%, due to a higher average royalty per ton and increased production. The average royalty per ton increased to $2.99 in 2006 from $2.74 in 2005. 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, for most of 2006, stronger market conditions for coal resulting in higher prices. Coal production by our lessees increased primarily due to production on our Illinois Basin property, which we acquired in the third quarter of 2005, and production on our Central Appalachian property due to the Huff Creek Acquisition in May 2006.

Coal services revenues increased primarily due to increased equity earnings from our coal handling joint venture and increased revenues from coal handling facilities that processed higher volumes. Our newly constructed facility on our Central Appalachian property began operations in October 2006 and contributed $0.2 million to coal services revenues in 2006.

Other revenues increased primarily due to the following factors. In 2006 and 2005, we earned $1.7 million and $0.8 million in revenues for the management of certain coal properties. Forfeiture income increased to $1.9 million in 2006 from $0.8 million in 2005 due to timing of lease terms. In 2006 and 2005, we recognized $0.8 million and $0.4 million in railcar rental income related to railcars we purchased in June 2005. In 2006 and 2005, we recognized $1.9 million and $1.3 million of wheelage fees, primarily as a result of the Alloy Acquisition. These increases were partially offset by a decrease from $1.4 million in 2005 to $1.0 million in 2006 in royalty income from oil and natural gas royalty interests acquired in the March 2005 Coal River Acquisition. Further offsetting the increases was $1.5 million we received in 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents.

*Expenses.* Operating expenses increased to $8.6 million in 2006 from $5.8 million in 2005, or 49%, due to production on our subleased Central Appalachian property acquired in the Huff Creek Acquisition in May 2006. This increase was partially offset by a decrease in production from other subleased properties primarily resulting from the movement of longwall mining operations at one of these properties. Fluctuations in production on subleased properties have a direct impact on royalty expense. General and administrative expenses increased due to absorbing operations related to our 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to our general partner for shared corporate overhead costs. Depreciation, depletion and amortization expense increased due to the increase in production and a higher depletion rate on recently acquired reserves.

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

The following table sets forth a summary of certain financial and other data for our coal segment and the percentage change for the periods indicated:

| | Year Ended December 31, | | % |
|---|---|---|---|
| | 2005 | 2004 | Change |
| | (in thousands, except as noted) | | |
| ***Financial Highlights*** | | | |
| **Revenues** | | | |
| Coal royalties | $82,725 | $69,643 | 19% |
| Coal services | 5,230 | 3,787 | 38% |
| Other | 7,800 | 2,200 | 255% |
| Total revenues | 95,755 | 75,630 | 27% |
| **Expenses** | | | |
| Operating | 5,755 | 7,224 | (20)% |
| Taxes other than income | 1,129 | 948 | 19% |
| General and administrative | 9,237 | 8,307 | 11% |
| Depreciation, depletion and amortization | 17,890 | 18,632 | (4)% |
| Total expenses | 34,011 | 35,111 | (3)% |
| **Operating income** | $61,744 | $40,519 | 52% |
| ***Operating Statistics*** | | | |
| Royalty coal tons produced by lessees (tons in millions) | 30,227 | 31,181 | (3)% |
| Average royalty per ton ($/ton) | $ 2.74 | $ 2.23 | 23% |

*Revenues.* Coal royalty revenues increased to $82.7 million in 2005 from $69.6 million in 2004, or 19%, due to a higher average royalty per ton despite a 3% decrease in production. The average royalty per ton increased 23% 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 we acquired in July 2005 in the Illinois Basin.

Coal services revenues increased 38% to $5.2 million in 2005 from $3.8 million in 2004. The increase in coal services revenues primarily related to increased equity earnings from the coal handling joint venture in which we acquired a 50% 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 255% to $7.8 million in 2005 from $2.2 million in 2004 primarily due to the following factors. We received $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 $1.4 million of royalty income in 2005 from the oil and natural gas royalty interests acquired in the March 2005 Coal River Acquisition, $0.8 million in fees for the management of certain coal properties and $0.4 million of rental income from railcars purchased in the second quarter of 2005.

*Expenses.* Operating expenses decreased to $5.8 million in 2005 from $7.2 million in 2004, or 20%, 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% 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 expense is consistent with the decrease in production.

*Natural Gas Midstream Segment*

We began operating our natural gas midstream segment on March 3, 2005 with the acquisition of Cantera's natural gas midstream business. The results of operations of the natural gas midstream segment since that date are discussed below.

The following table sets forth a summary of certain financial and other data for our natural gas midstream segment and the percentage change for the periods indicated:

| | Year Ended December 31, | | % |
|---|---|---|---|
| | 2006 | 2005 (1) | Change |
| | (in thousands) | | |
| ***Financial Highlights*** | | | |
| **Revenues** | | | |
| Residue gas | $259,764 | $233,208 | 11% |
| Natural gas liquids | 130,675 | 106,453 | 23% |
| Condensate | 9,989 | 7,322 | 36% |
| Gathering and transportation fees | 2,287 | 1,674 | 37% |
| Total natural gas midstream revenues | 402,715 | 348,657 | 16% |
| Marketing revenue, net | 2,195 | 1,936 | 13% |
| Total revenues | 404,910 | 350,593 | 15% |
| **Expenses** | | | |
| Cost of gas purchased | 334,594 | 303,912 | 10% |
| Operating | 11,403 | 9,347 | 22% |
| Taxes other than income | 1,420 | 1,268 | 12% |
| General and administrative | 11,023 | 6,982 | 58% |
| Depreciation and amortization | 17,094 | 12,738 | 34% |
| Total operating expenses | 375,534 | 334,247 | 12% |
| **Operating income** | $ 29,376 | $ 16,346 | 80% |
| ***Operating Statistics*** | | | |
| Inlet volumes (MMcf) | 55,991 | 38,875 | 44% |
| Midstream processing margin (2) | $ 68,121 | $ 44,745 | 52% |

(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.

The financial and other data presented in the table above for 2005 include ten months of operations of our midstream business. One of the primary reasons for the significant differences in our results of operations for 2006 as compared to 2005 is that the 2006 data includes 12 full months of operations of the midstream business.

*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 increase in natural gas midstream revenues was primarily a result of an additional two months of operations in 2006 and higher average NGL and condensate prices in 2006.

*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. Expenses generally increased due to an additional two months of activity in 2006. The following paragraphs describe other factors contributing to the change in expenses.

Cost of gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage of proceeds and keep-whole contracts. The increase in the cost of gas purchased was primarily due to overall volume of natural gas purchased in 2006. Included in cost of gas purchased for 2006 was a $4.6 million non-cash charge to reserve for amounts related to balances assumed as part of the Cantera Acquisition. The following table shows a summary of the effects of derivative activities on midstream processing margin:

| | Year Ended December 31, | |
|---|---|---|
| | 2006 | 2005 |
| | (in thousands) | |
| Midstream processing margin, as reported | $ 68,121 | $44,745 |
| Derivatives losses included in midstream processing margin | 1,953 | (988) |
| Midstream processing margin before impact of derivatives | 70,074 | 43,757 |
| Cash settlements on derivatives | (19,436) | (4,752) |
| Midstream processing margin, adjusted for derivatives | $ 50,638 | $39,005 |

Operating expenses increased due to rent and maintenance costs associated with additional compressors. General and administrative expenses increased primarily due to additional personnel added to support the business and recent acquisitions, and increased reimbursement to our general partner for shared corporate overhead costs from $0.8 million in 2005 to $2.4 million in 2006. Depreciation and amortization expense increased due to depreciation on the pipeline acquired in the June 2006 Transwestern Acquisition and recent gathering system expansions.

*Other*

*Interest Expense.* Interest expense increased by $4.7 million from $14.1 million in 2005 to $18.8 million in 2006. The increase was primarily due to interest incurred on additional borrowings under the Revolver to finance the Cantera Acquisition, the Transwestern Acquisition and coal property acquisitions in 2005 and 2006 and a general increase in interest rates. Interest expense increased by $6.8 million from $7.3 million in 2004 to $14.1 million in 2006. The increase was primarily due to interest incurred on additional borrowings to finance the Cantera Acquisition and coal property acquisitions in 2005.

*Derivatives.* Because during the first quarter of 2006 our natural gas derivatives and a large portion of our NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

Derivative losses were $11.3 million for 2006 and included a net $11.2 million loss for settlements and mark-to-market adjustments and a $0.1 million unrealized loss for changes in hedge effectiveness. The unrealized loss due to changes in fair market value was associated with derivative contracts that we no longer accounted for using hedge accounting and represented changes in the fair value of our open contracts during the period. The unrealized loss for changes in hedge effectiveness was associated with hedging contracts that we accounted for using hedge accounting under SFAS No. 133. Derivative losses for 2005 included a $13.9 million unrealized loss representing the change in market value of derivative agreements between the time we entered into the agreements in January 2005 and the time the derivative agreements qualified for hedge accounting after closing the acquisition of the natural gas midstream business in March 2005.

**Environmental Matters**

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, 2006 and 2005, our environmental liabilities included $1.6 million and $2.5 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. For a summary of the environmental laws and regulations applicable to our operations, see Item 1, "Business—Government Regulation and Environmental Matters."

**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 NGL, crude oil, natural gas and coal price risks and interest rate risk.

We are also indirectly exposed to the credit risk of our customers and lessees. If our customers or lessees become financially insolvent, they may not be able to continue operating or meeting their payment obligations.

### Price Risk Management

Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to seek to mitigate the price risks associated with fluctuations in natural gas, NGL and crude oil prices as they relate to our natural gas midstream business. Prior to May 1, 2006, these financial instruments were historically designated as cash flow hedges and accounted for in accordance with SFAS No. 133. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets is significantly affected by fluctuations in the prices of natural gas, NGLs and crude oil.

For the year ended December 31, 2006, we reported a net $11.3 million derivative loss. The derivative loss included a net $11.2 million loss for settlements and mark-to-market adjustments and a $0.1 million unrealized loss for changes in hedge effectiveness. Because during the first quarter of 2006 our natural gas derivatives and a large portion of our NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. We will recognize hedging losses of $4.6 million in 2007 and $5.5 million in 2008 related to settlements of the hedged transactions for which we deferred net losses in accumulated comprehensive income through April 30, 2006. The discontinuation of hedge accounting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices. See the discussion and tables in Note 8 in the Notes to Consolidated Financial Statements for a description of our derivative program. The following table lists our open mark-to-market derivative agreements and their fair values as of December 31, 2006:

| | Average Volume Per Day | Weighted Average Price | Estimated Fair Value (in thousands) |
|---|---|---|---|
| | (in gallons) | (per gallon) | |
| **Ethane Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 34,440 | $0.5050 | (1,277) |
| First Quarter 2008 through Fourth Quarter 2008 | 34,440 | $0.4700 | (1,377) |
| | (in gallons) | (per gallon) | |
| **Propane Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 26,040 | $0.7550 | (1,543) |
| First Quarter 2008 through Fourth Quarter 2008 | 26,040 | $0.7175 | (1,795) |
| | (in barrels) | (per barrel) | |
| **Crude Oil Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 560 | $ 50.80 | (2,815) |
| First Quarter 2008 through Fourth Quarter 2008 | 560 | $ 49.27 | (3,446) |
| | (in MMbtu) | (per MMbtu) | |
| **Natural Gas Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 4,000 | $ 6.97 | (11) |
| First Quarter 2008 through Fourth Quarter 2008 | 4,000 | $ 6.97 | 1,479 |
| December 2006 Settlements | | | (1,350) |
| Natural gas midstream segment commodity derivatives—net liability | | | $(12,135) |

Taking into account the derivative positions described above, for every $1.00 per MMbtu decrease or increase in natural gas prices, natural gas midstream gross processing margin and operating income would increase or decrease by approximately $8.1 million. Taking into account the derivative positions described above, for every $5.00 per barrel increase or decrease in the oil prices natural gas midstream gross processing margin and operating income would increase or decrease by approximately $10.0 million.

### Interest Rate Risk

As of December 31, 2006, we had $143.2 million of outstanding indebtedness under the Revolver which carries 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 weighted average fixed rate of 4.22% plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2006 would cost us approximately $0.8 million in additional interest expense.

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

## PENN VIRGINIA RESOURCES, L.P. AND SUBSIDIARIES

## INDEX TO FINANCIAL SECTION

## 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 as of December 31, 2006 and 2005, 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, 2006. These consolidated financial statements are the responsibility of Penn Virginia Resource Partners, L.P.'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, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Penn Virginia Resource Partners, L.P.'s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
February 28, 2007

## 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., a Delaware limited partnership, maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Penn Virginia Resource Partners, L.P. 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 Penn Virginia Resource Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by COSO. Also, in our opinion, Penn Virginia Resource Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Penn Virginia Resource Partners, L.P. as of December 31, 2006 and 2005, 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, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 28, 2007

## PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| **Revenues** | | | |
| Natural gas midstream | $402,715 | $348,657 | $ — |
| Coal royalties | 98,163 | 82,725 | 69,643 |
| Coal services | 5,864 | 5,230 | 3,787 |
| Other | 11,149 | 9,736 | 2,200 |
| Total revenues | 517,891 | 446,348 | 75,630 |
| **Expenses** | | | |
| Cost of midstream gas purchased | 334,594 | 303,912 | — |
| Operating | 20,003 | 15,102 | 7,224 |
| Taxes other than income | 2,354 | 2,397 | 948 |
| General and administrative | 20,627 | 16,219 | 8,307 |
| Depreciation, depletion and amortization | 37,493 | 30,628 | 18,632 |
| Total expenses | 415,071 | 368,258 | 35,111 |
| **Operating income** | 102,820 | 78,090 | 40,519 |
| **Other income (expense)** | | | |
| Interest expense | (18,821) | (14,054) | (7,267) |
| Interest income | 1,189 | 1,149 | 1,063 |
| Derivatives | (11,260) | (14,024) | — |
| **Net income** | $ 73,928 | $ 51,161 | $34,315 |
| General partner's interest in net income | $ 8,321 | $ 2,122 | $ 686 |
| Limited partners' interest in net income | $ 65,607 | $ 49,039 | $33,629 |
| Basic and diluted net income per limited partner unit, common, Class B and subordinated (see Note 2) | $ 1.56 | $ 1.22 | $ 0.93 |
| Weighted average number of units outstanding, basic and diluted: | | | |
| Common | 35,639 | 29,464 | 21,478 |
| Subordinated | 6,375 | 10,838 | 14,662 |

See accompanying notes to consolidated financial statements.

## PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

### CONSOLIDATED BALANCE SHEETS
### (in thousands, except unit amounts)

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | $ 11,440 | $ 23,193 |
| Accounts receivable | 66,987 | 76,398 |
| Derivative assets | 449 | 10,235 |
| Other current assets | 2,587 | 2,724 |
| Total current assets | 81,463 | 112,550 |
| Property, plant and equipment | 665,135 | 535,040 |
| Accumulated depreciation, depletion and amortization | (108,622) | (76,258) |
| Net property, plant and equipment | 556,513 | 458,782 |
| Equity investments | 25,355 | 26,672 |
| Goodwill | 7,718 | 7,718 |
| Intangibles, net | 33,045 | 38,051 |
| Derivative assets | 2,455 | 8,536 |
| Other long-term assets | 7,474 | 5,570 |
| Total assets | $ 714,023 | $657,879 |
| **Liabilities and Partners' Capital** | | |
| Current liabilities | | |
| Accounts payable | $ 52,006 | $ 58,216 |
| Accrued liabilities | 11,247 | 9,788 |
| Current portion of long-term debt | 10,832 | 8,108 |
| Deferred income | 6,999 | 5,073 |
| Derivative liabilities | 6,996 | 20,700 |
| Total current liabilities | 88,080 | 101,885 |
| Deferred income | 6,592 | 10,194 |
| Other liabilities | 3,339 | 3,749 |
| Derivative liabilities | 6,618 | 11,246 |
| Long-term debt | 207,214 | 246,846 |
| Commitments and contingencies (Note 14) | | |
| Partners' capital | | |
| Common units (42,060,974 at December 31, 2006 and 33,994,650 at December 31, 2005) | 302,938 | 296,038 |
| Common units—Class B (4,012,164 at December 31, 2006) | 102,500 | — |
| Subordinated units (7,649,880 at December 31, 2005) | — | (10,440) |
| General partner interest | 5,394 | 3,252 |
| Accumulated other comprehensive income (loss) | (8,652) | (4,891) |
| Total partners' capital | 402,180 | 283,959 |
| Total liabilities and partners' capital | $ 714,023 | $657,879 |

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, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| **Cash flows from operating activities** | | | |
| Net income | $ 73,928 | $ 51,161 | $ 34,315 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 37,493 | 30,628 | 18,632 |
| Commodity derivative contracts: | | | |
| Total derivative losses (gains) | 13,213 | 13,036 | — |
| Cash settlements on derivatives | (19,436) | (4,752) | — |
| Non-cash interest expense | 769 | 1,735 | 1,678 |
| Equity earnings, net of distributions received | 1,317 | 1,269 | 561 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | 9,411 | (27,318) | (1,759) |
| Accounts payable | (5,847) | 18,090 | 81 |
| Accrued liabilities | (958) | 6,490 | 33 |
| Deferred income | (1,676) | 2,063 | 2,295 |
| Other assets and liabilities | (870) | 1,310 | (1,054) |
| Net cash provided by operating activities | 107,344 | 93,712 | 54,782 |
| **Cash flows from investing activities** | | | |
| Acquisitions, net of cash acquired | (91,259) | (290,938) | (28,675) |
| Additions to property, plant and equipment | (38,453) | (12,735) | (855) |
| Other | 36 | 52 | 1,104 |
| Net cash used in investing activities | (129,676) | (303,621) | (28,426) |
| **Cash flows from financing activities** | | | |
| Distributions to partners | (66,954) | (51,949) | (39,191) |
| Proceeds from borrowings | 85,800 | 288,800 | 28,500 |
| Repayments of borrowings | (122,900) | (151,600) | (2,500) |
| Proceeds from issuance of partners' capital | 115,008 | 129,239 | — |
| Payments for debt issuance costs | (375) | (2,385) | (1,234) |
| Net cash provided by (used in) financing activities | 10,579 | 212,105 | (14,425) |
| Net increase (decrease) in cash and cash equivalents | (11,753) | 2,196 | 11,931 |
| Cash and cash equivalents—beginning of period | 23,193 | 20,997 | 9,066 |
| Cash and cash equivalents—end of period | $ 11,440 | $ 23,193 | $ 20,997 |
| **Supplemental disclosure:** | | | |
| Cash paid for interest | $ 18,312 | $ 12,138 | $ 5,472 |
| **Noncash investing and financing activities:** | | | |
| Issuance of partners' capital for acquisition | $ — | $ 10,415 | $ 1,060 |
| Assumption of liabilities in acquisitions | $ — | $ 3,981 | $ — |

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, 2003 | 20,746 | $171,485 | — | $ — | 15,300 | $(18,060) | $ 375 | $ — | $153,800 | $22,690 |
| Issuance of units | 102 | 1,060 | — | — | — | — | — | — | 1,060 | |
| Conversion of subordinated units | 3,826 | (5,483) | — | — | (3,826) | 5,483 | — | — | — | |
| Distributions ($1.06 per unit) | — | (22,190) | — | — | 0 | (16,218) | (783) | — | (39,191) | |
| Net income allocation | — | 19,866 | — | — | — | 13,763 | 686 | — | 34,315 | $34,315 |
| Balance at December, 31, 2004 | 24,674 | 164,738 | — | — | 11,474 | (15,032) | 278 | — | 149,984 | $34,315 |
| Capital contributions | — | — | — | — | — | — | 2,783 | — | 2,783 | |
| Issuance of units | 5,496 | 136,871 | — | — | — | — | — | — | 136,871 | |
| Conversion of subordinated units | 3,824 | (5,538) | — | — | (3,824) | 5,538 | — | — | — | |
| Distributions ($1.24 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 | 33,994 | 296,038 | — | — | 7,650 | (10,440) | 3,252 | (4,891) | 283,959 | $46,270 |
| Capital contributions | — | — | — | — | — | — | 2,298 | — | 2,298 | |
| Issuance of units | 416 | 10,601 | 4,012 | 102,109 | — | — | — | — | 112,710 | |
| Conversion of subordinated units | 7,650 | (10,658) | — | — | (7,650) | 10,658 | — | — | — | |
| Distributions ($1.475 per unit) | — | (50,142) | — | — | — | (11,284) | (5,528) | — | (66,954) | |
| Net income allocation | — | 57,099 | — | 391 | — | 11,066 | 5,372 | — | 73,928 | $73,928 |
| Other comprehensive loss | — | — | — | — | — | — | — | (3,761) | (3,761) | (3,761) |
| Balance at December 31, 2006 | 42,060 | $302,938 | 4,012 | $102,500 | — | $ — | $ 5,394 | $(8,652) | $402,180 | $70,167 |

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 July 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 natural gas 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 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.

Our general partner is Penn Virginia Resource GP, LLC, which was a wholly owned subsidiary of Penn Virginia through November 2006. In December 2006, Penn Virginia contributed its ownership interest in our general partner to Penn Virginia GP Holdings, L.P. ("PVG") in exchange for common units of PVG. Penn Virginia continues to hold a significant interest in us through its indirect controlling interest in PVG. PVG completed its initial public offering in December 2006 and used the proceeds from the offering to purchase 0.4 million newly issued common units and 0.4 million newly issued Class B units from us. Penn Virginia owns an approximately 82% limited partner interest in PVG as well as the non-economic general partner interest in PVG. PVG owns an approximately 42% limited partner interest in us as well as a 2% general partner interest in us.

### 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 determination of fair value is based upon regional market and facility type information. 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 expense on our consolidated statements of income.

*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 on 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, 2006 and 2005 based upon the purchase price allocation for the Cantera Acquisition (as defined in Note 3). The goodwill has been allocated to our natural gas midstream segment. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets,* goodwill is assessed at least annually for impairment. We tested goodwill for impairment during the fourth quarter of 2006 and determined that no impairment charge was necessary.

*Intangibles*

Intangible assets at December 31, 2006 and 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). 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 for the years ended December 31, 2006 and 2005 was approximately $5.0 million and $4.2 million. There were no intangible assets or related amortization in 2004. As of December 31, 2006, accumulated amortization of intangible assets was $9.2 million. The following table summarizes our estimated aggregate amortization expense for the next five years (in thousands):

| | |
|---|---|
| 2007 | $ 4,106 |
| 2008 | 3,485 |
| 2009 | 3,219 |
| 2110 | 3,006 |
| 2111 | 2,764 |
| Thereafter | 16,465 |
| Total | $33,045 |

*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 81% of our accounts receivable at December 31, 2006 resulted from natural gas midstream customers and approximately 19% resulted from accrued revenues from coal lessee production. Approximately 31% of total accounts receivable at December 31, 2006 related to two 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, 2006 and 2005 was $75.4 million and $81.2 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 midstream 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 PVR's best estimates of coal mined on its 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*. The fair values of our derivative instruments are determined based on third party forward price quotes. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by the board of directors of our general partner.

We historically have entered into derivative financial instruments that would qualify for hedge accounting under SFAS No. 133. Hedge accounting affects the timing of revenue recognition and cost of midstream gas purchased in our consolidated statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the hedged transaction settles. Because during the first quarter of 2006 our natural gas derivatives and a large portion of our NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). Because we no longer use hedge accounting for our commodity derivatives, we could experience significant changes in the estimate of derivative gain or loss recognized in revenues and cost of midstream gas purchased due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle (see Note 8). This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

*Income Taxes*

As a partnership, we are not a taxable entity and have no federal income tax liability. The tax effect of our activities are includable in the federal and state income tax returns of our 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 available to limited partners by the weighted average number of limited partner units outstanding during the period. To calculate net income available to limited partners, income is first allocated to our general partner based on the amount of incentive distributions to which it is entitled and the remainder is allocated between the limited partners and our general partner based on percentage ownership in the Partnership. Emerging Issues Task Force ("EITF") Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*, addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. EITF Issue No. 03-6 provides that in any accounting period where our net income exceeds our distribution for such period, we are required to present earnings per unit as if all of the earnings for the period were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF Issue No. 03-6 does not impact our actual distributions for any period, but it can have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of our earnings, as if distributed, is allocated to the incentive distribution rights held by our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where net income does not exceed our distributions for such period, EITF Issue No. 03-6 does not have any impact on our earnings per unit calculation. A reconciliation of net income and weighted average units used in computing basic and diluted earnings per unit is as follows (in thousands, except per unit data):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Net income | $73,928 | $51,161 | $34,315 |
| Less: General partner's incentive distributions paid | (4,273) | (910) | — |
| Subtotal | 69,655 | 50,251 | 34,315 |
| General partner interest in net income | (1,099) | (1,212) | (686) |
| Limited partners' interest in net income | 68,556 | 49,039 | 33,629 |
| Additional earnings allocation to general partner under EITF 03-6 | (2,949) | — | — |
| Net income available to limited partners under EITF 03-6 | $65,607 | $49,039 | $33,629 |
| Weighted average limited partner units, basic and diluted | 42,014 | 40,302 | 36,140 |
| Basic and diluted net income per limited partner unit | $ 1.56 | $ 1.22 | $ 0.93 |

*Unit-Based Compensation*

Our general partner has a long-term incentive plan that permits the grant of awards 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. We reimburse our general partner for payments made pursuant to the long-term incentive plan.

*New Accounting Standards*

In September 2006, the Financial Accounting Standards Board (the "FASB") issued FASB Staff Position ("FSP") AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* FSP AUG AIR-1 prohibits companies from accruing as a liability the future costs of periodic major overhauls and maintenance of plant and equipment. FSP AUG AIR-1 is effective for fiscal years beginning after December 15, 2006. We expect that the provisions of FSP AUG AIR-1 will not have a material impact on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* a standard that provides enhanced guidance for using fair value to measure assets and liabilities. SFAS No. 157 also responds to investors' requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS No. 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 establishes a fair value hierarchy that prioritizes the information used to develop fair value assumptions. SFAS No. 157 is effective for fiscal years and interim periods beginning after November 15, 2007. We have not yet determined the impact on our financial statements of adopting SFAS No. 157 effective January 1, 2008.

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB No. 108 expresses the SEC staff's views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct errors existing in prior years that previously had been considered immaterial, quantitatively and qualitatively, based on appropriate use of the registrant's approach. SAB No. 108 describes the circumstances where this would be appropriate as well as required disclosures to investors. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006. We adopted SAB No. 108 as of December 31, 2006. Adoption of SAB No. 108 had no effect on our financial position or results of operations.

### 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 us. 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. 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 the 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 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 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 our consolidated results of operations 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 |
| | (unaudited) (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 | $ 1.22 | $ 1.09 |

**4. Other Acquisitions**

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

In December 2006, we acquired ownership and rights to approximately 22 million tons of coal reserves. The reserves are located in Henderson County, Kentucky. The purchase price was $9.3 million and was funded with cash.

In June 2006, we acquired approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma (the "Transwestern Acquisition"). These assets are contiguous to our Beaver/Perryton System. We paid for $14.7 million in cash for the acquisition. Subsequently, we borrowed $14.7 million under our revolving credit facility to replenish the cash used in the Transwestern Acquisition.

In May 2006, we acquired the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Boone, Logan and Wyoming Counties, West Virginia (the "Huff Creek Acquisition"). The purchase price was $65.0 million and was funded with long-term debt under our revolving credit facility.

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 assumption of $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 41 million tons of these coal reserves are leased to affiliates of Peabody Energy Corporation (NYSE: BTU).

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 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 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 contained approximately 2.8 billion cubic feet equivalent of net proved oil and gas reserves.

In July 2004, we acquired from affiliates of Massey Energy Company a 50% 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.

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, 2006 | December 31, 2005 |
|---|---|---|
| | (in thousands) | |
| Coal properties | $ 414,935 | $340,439 |
| Compressor stations | 49,071 | 45,405 |
| Gathering systems | 121,467 | 91,216 |
| Coal services equipment | 38,755 | 23,351 |
| Processing plants | 19,273 | 14,533 |
| Land | 11,291 | 10,675 |
| Oil and gas properties | 5,395 | 5,324 |
| Other property and equipment | 4,948 | 4,097 |
| | 665,135 | 535,040 |
| Accumulated depreciation, depletion and amortization | (108,622) | (76,258) |
| Net property and equipment | $ 556,513 | $458,782 |

## 6. Equity Investments

As described in Note 4, "Other Acquisitions," we acquired a 50% 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, 2006 and 2005, our equity investment totaled $25.4 million and $26.7 million, which exceeded our portion of the underlying equity in net assets by $8.7 million and $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 $1.3 million in 2006, $1.1 million in 2005 and $0.4 million in 2004, with a corresponding increase in the investment. The joint venture generally pays to PVR quarterly distributions of PVR's portion of the joint venture's cash flows. PVR received cash distributions from the joint venture of $2.7 million in 2006, $2.3 million in 2005 and $1.0 million in 2004. 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, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (in thousands) | | |
| Balance at beginning of period | $1,692 | $1,514 | $1,334 |
| Charges to expense | 60 | 178 | 180 |
| Forfeiture of prepaid minimum | (15) | — | — |
| Balance at end of period | $1,737 | $1,692 | $1,514 |

## 8. Derivative Instruments

*Discontinuation of Hedge Accounting*

Because during the first quarter of 2006 our natural gas derivatives and a large portion of our NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements (see below for further discussions), we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

*Natural Gas Midstream Segment Commodity Derivatives*

We utilize swap derivative contracts to hedge against the variability in cash flows associated with forecasted natural gas midstream revenues and cost of gas purchased. While the use of derivative instruments limits the risk of adverse price movements, their use also may limit future revenues or cost savings from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract.

The fair values of our derivative agreements are determined based on forward price quotes and regression analysis for the respective commodities as of December 31, 2006. The following table sets forth our positions as of December 31, 2006 for commodities related to natural gas midstream revenues (ethane, propane and crude oil) and cost of midstream gas purchased (natural gas):

| | Average Volume Per Day | Weighted Average Price | Estimated Fair Value (in thousands) |
|---|---|---|---|
| | (in gallons) | (per gallon) | |
| **Ethane Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 34,440 | $0.5050 | (1,277) |
| First Quarter 2008 through Fourth Quarter 2008 | 34,440 | $0.4700 | (1,377) |
| | (in gallons) | (per gallon) | |
| **Propane Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 26,040 | $0.7550 | (1,543) |
| First Quarter 2008 through Fourth Quarter 2008 | 26,040 | $0.7175 | (1,795) |
| | (in barrels) | (per barrel) | |
| **Crude Oil Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 560 | $ 50.80 | (2,815) |
| First Quarter 2008 through Fourth Quarter 2008 | 560 | $ 49.27 | (3,446) |
| | (in MMbtu) | (per MMbtu) | |
| **Natural Gas Swaps** | | | |
| First Quarter 2007 through Fourth Quarter 2007 | 4,000 | $ 6.97 | (11) |
| First Quarter 2008 through Fourth Quarter 2008 | 4,000 | $ 6.97 | 1,479 |
| December 2006 Settlements | | | (1,350) |
| Natural gas midstream segment commodity derivatives—net liability | | | $(12,135) |

Based upon our assessment of derivative agreements at December 31, 2006, we reported (i) a net derivative liability related to the natural gas midstream segment of $12.1 million, (ii) a loss in accumulated other comprehensive income of $10.1 million and (iii) a net loss on derivatives for hedge ineffectiveness of $0.1 million for the year ended December 31, 2006 related to derivatives in the natural gas midstream segment. The following table summarizes the effects of commodity derivative activities on our consolidated statements of income (in thousands):

| | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Income statement caption: | | | |
| Midstream revenue | $(10,331) | $ (3,871) | $— |
| Cost of gas purchased | 8,378 | 4,859 | — |
| Derivatives | (11,260) | (14,024) | — |
| Increase (decrease) in net income | $(13,213) | $(13,036) | $— |
| Realized and unrealized derivative impact: | | | |
| Cash paid for derivative settlements | $(19,436) | $ (4,752) | $— |
| Unrealized derivative gain (loss) | 6,223 | (8,284) | — |
| Increase (decrease) in net income | $(13,213) | $(13,036) | $— |

At the time we entered into our natural gas derivatives and certain NGL derivatives, physical purchase prices of natural gas correlated well with NYMEX natural gas prices and physical sales prices of NGLs correlated well with NGL index prices. However, in the second half of 2005, basis differentials for certain derivative agreements widened as NYMEX natural gas prices and NGL index prices reached historically high levels. In the first quarter of 2006, our correlation assessment indicated that our NYMEX natural gas derivatives and certain NGL derivatives could no longer be considered "highly effective" hedges under the parameters of the accounting rules. Consequently, we discontinued hedge accounting effective January 1, 2006 for our natural gas derivatives and certain NGL derivatives that were no longer considered highly effective. As discussed above, beginning May 1, 2006, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives. We will recognize hedging losses of $4.6 million in 2007 and $5.5 million in 2008 related to settlements of the hedged transactions for which we deferred net losses in accumulated comprehensive income through April 30, 2006.

*Interest Rate Swaps*

In September 2005, we entered into interest rate swap agreements (the "Revolver Swaps") to establish fixed rates on $60 million of the portion of the outstanding balance on our revolving credit facility that is based on the London Inter Bank Offering Rate ("LIBOR") until March 2010. We pay a weighted average fixed rate of 4.22% 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 Swaps 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. We reported (i) a derivative asset of approximately $1.4 million at December 31, 2006 and (ii) a gain in accumulated other comprehensive income of $1.4 million at December 31, 2006 related to the Revolver Swaps. In connection with periodic settlements, we recognized $0.5 million in net hedging gains in interest expense for the year ended December 31, 2006. Based upon future interest rate curves at December 31, 2006, we expect to realize $0.4 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. 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, | |
|---|---|---|
| | 2006 | 2005 |
| | (in thousands) | |
| Balance at beginning of period | $1,458 | $ 723 |
| Adoption of FIN 47 | — | 635 |
| Liabilities incurred | 301 | — |
| Accretion expense | 122 | 100 |
| Balance at end of period | $1,881 | $1,458 |

## 10. Long-Term Debt

Long-term debt as of December 31, 2006 and 2005 consisted of the following:

| | December 31, | |
|---|---|---|
| | 2006 | 2005 |
| | (in thousands) | |
| Revolving credit facility—variable rate of 6.1 percent at December 31, 2006 | $143,200 | $172,000 |
| Senior unsecured notes (1) | 74,846 | 82,954 |
| | 218,046 | 254,954 |
| Less: Current maturities | (10,832) | (8,108) |
| Total long-term debt | $207,214 | $246,846 |

(1) Includes negative fair value adjustments of $0.6 million and $0.7 million as of December 31, 2006 and 2005 related to a former interest rate swap agreement that was designated as a fair value hedge. The swap agreement was settled in June 2005.

*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 was set to mature in March 2010 and a $110 million term loan. As of December 31, 2006, we had $143.2 million of outstanding borrowings under the Revolver. During 2005 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. We used the proceeds from the sale of common units and Class B units to PVG in December 2006 to pay down $114.6 million of the Revolver. 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, 2006. In 2006 and 2005, we incurred commitment fees each year 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 Revolver remained unchanged and fluctuates based on our ratio of total indebtedness to EBITDA. In December 2006, we further amended the credit agreement to achieve a more favorable interest rate and to extend the maturity date to December 2011. Interest is payable at a base rate plus an applicable margin of up to 0.75% if we select the base rate borrowing option under the Revolver, or at a rate derived from LIBOR plus an applicable margin ranging from 0.75% to 1.75% 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 $257.0 million at December 31, 2006. At the current $300 million limit on the Revolver, and given our outstanding balance of $143.2 million and $1.6 million in letters of credit, we could borrow up to $155.2 million without exercising our one-time option to expand the Revolver. In order to utilize the full extent of the $257.0 million borrowing capacity, we would need to exercise our one-time option to expand the Revolver by $150 million. The Revolver prohibits us from making distributions to our partners if any potential default or event of default, as defined in the Revolver, occurs or would result from the distributions. 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, 2006, we were in compliance with all of our covenants under the Revolver.

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 initially bore interest at a fixed rate of 5.77% 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, 2006, 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% in the fixed interest rate on the Notes, from 5.77% to 6.02%. The amendment to the Notes also requires that we obtain an annual confirmation of our credit rating, with a 1.00% increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. In March 2006, our investment grade credit rating was confirmed as investment grade by Dominion Bond Rating Services.

*Debt Maturities*

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

| | |
|---|---|
| 2007 | $ 11,000 |
| 2008 | 12,700 |
| 2009 | 14,100 |
| 2010 | 13,400 |
| 2011 | 154,000 |
| Thereafter | 13,400 |
| Total principal | 218,600 |
| Less: Terminated interest rate swap | (554) |
| Total debt, including current maturities | $218,046 |

**11. Partnership Capital and Distributions**

As of December 31, 2006, partners' capital consisted of 42.1 million common units, representing an 89% limited partner interest, 4.0 million Class B units, representing a 9% limited partner interest, and a 2% general partner interest. As of December 31, 2006, affiliates of Penn Virginia, in the aggregate, owned a 44% interest in us, consisting of 16.0 million common units, 4.0 million Class B units and a 2% general partner interest.

*Unit Split*

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 distributed 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 held of record at the close of business on March 28, 2006. All units and per unit data have been retroactively adjusted to reflect the unit split.

*Conversion of Subordinated Units*

On September 30, 2006, the subordination period with respect to our subordinated units ended. All outstanding subordinated units converted to common units on November 14, 2006, when the quarterly distribution was paid. At the time of conversion, the subordinated units converted into common units on a one-for-one basis.

*Cash Distributions*

We distribute 100% 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.

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 $0.25 per unit ($1.00 per unit on an annualized basis). We expect to make quarterly distributions of $0.25 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 $0.275 per unit | 98% | 2% |
| Second target—above $0.275 per unit up to $0.325 per unit | 85% | 15% |
| Third target—above $0.325 per unit up to $0.375 per unit | 75% | 25% |
| Thereafter—above $0.375 per unit | 50% | 50% |

The following table reflects the allocation of total cash distributions paid during each of the three years ended December 31, 2006 (in thousands, except per unit information):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Limited partner units | $61,427 | $50,018 | $38,403 |
| General partner interest (2%) | 1,254 | 1,021 | 788 |
| Incentive distribution rights | 4,273 | 910 | — |
| Total cash distributions paid | $66,954 | $51,949 | $39,191 |
| Total cash distributions paid per unit | $1.4750 | $1.2413 | $1.0600 |

On February 14, 2007, the board of directors of our general partner paid a $0.40 per unit quarterly distribution ($1.60 per unit on an annualized basis) to unitholders of record on February 5, 2007.

*Limited Call Right*

If at any time our general partner and its affiliates own more than 80% 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.

## 12. Related Party Transactions

*Sale of Units to PVG*

We sold 4.0 million newly issued Class B units and 0.4 million newly issued common units to PVG in December 2006 for $25.45 per Class B and common unit. The price was determined based on the weighted average market price per common unit for the ten trading days ended December 4, 2006. PVG also paid us $2.3 million to maintain its 2% general partner interest in us after the issuance of new Class B and common units. We used the total proceeds of $115 million to repay borrowings outstanding under our Revolver.

*General and Administrative*

Our general partner charges us for certain corporate administrative expenses which are allocable to us and our 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 $4.5 million, $2.6 million and $1.5 million for the years ended December 31, 2006, 2005 and 2004. 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 $2.0 million and $2.8 million as of December 31, 2006 and 2005. 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.

*Marketing Revenues*

Connect Energy Services, LLC, a wholly-owned subsidiary of the Partnership, earned $0.4 million in fees for marketing a portion of Penn Virginia Oil & Gas, L.P.'s natural gas production during 2006. The marketing agreement was effective September 1, 2006. Penn Virginia Oil & Gas, L.P. is a wholly-owned subsidiary of Penn Virginia. Marketing revenues are included in other revenues on our consolidated statements of income.

## 13. Long-Term Incentive Plan

Our general partner has a long-term incentive plan that permits the grant of awards covering an aggregate of 600,000 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. We reimburse our general partner for payments made pursuant to the long-term incentive plan. Compensation expense related to the long-term incentive plan totaled $1.9 million, $1.4 million and $0.4 million for the years ended December 31, 2006, 2005 and 2004.

*Common Units*

Our general partner granted 1,795 common units at a weighted average grant-date fair value of $26.01 per unit to non-employee directors in 2006. Our general partner granted 876 common units at a weighted average grant-date fair value of $25.36 per unit to non-employee directors in 2005. Our general partner granted 9,922 common units at a weighted average grant-date fair value of $17.42 per unit to non-employee directors in 2004.

*Restricted Units*

Restricted units vest upon terms established by the compensation and benefits committee. 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. Restricted units granted in 2006 and 2005 generally vest over a three-year period, with one-third vesting in each year. Restricted units granted in 2004 vested on the first anniversary of the date of grant.

A summary of the status of our nonvested restricted units as of December 31, 2006, and changes during the year then ended, is presented below:

| | Nonvested Restricted Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1, 2006 | 113,624 | $18.81 |
| Granted | 82,320 | 28.83 |
| Vested | (81,116) | 26.64 |
| Forfeit | (614) | 27.99 |
| Nonvested at December 31, 2006 | 114,214 | $20.42 |

At December 31, 2006, we had $2.2 million of total unrecognized compensation cost related to nonvested restricted units. We expect to reimburse our general partner for that cost over a weighted-average period of 0.9 years. The total grant-date fair value of restricted units vested was $2.2 million in 2006, $0.4 million in 2005 and $0.4 million in 2004.

*Deferred Common Units*

A portion of the compensation to the 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.

The following table summarizes activity for our most recent fiscal year with respect to deferred common units awarded:

| | Deferred Common Units |
|---|---|
| Outstanding at January 1, 2006 | 21,710 |
| Granted | 23,636 |
| Converted to common units | (6,439) |
| Outstanding at December 31, 2006 | 38,907 |

The aggregate intrinsic value of deferred common units converted to common units in 2006 was $0.2 million. No deferred common units converted to common units in 2005 or 2004.

## 14. Commitments and Contingencies

*Rental Commitments*

Operating lease rental expense in the years ended December 31, 2006, 2005 and 2004 was $1.9 million, $0.9 million and $0.2 million. Minimum rental commitments for the next five years under all non-cancelable operating leases in effect at December 31, 2006 were as follows (in thousands):

| | |
|---|---|
| 2007 | $1,329 |
| 2008 | 1,126 |
| 2009 | 943 |
| 2010 | 907 |
| 2011 | 903 |
| Total minimum payments | $5,208 |

Our rental commitments primarily relate to equipment, building and 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 that the future rental commitments cannot be estimated with certainty; however, based on current knowledge and historical trends, we believe that we will incur approximately $0.9 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, 2006 and 2005, environmental liabilities included $1.6 million and $2.5 million, which represents 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.

*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.

**15. 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 each of the three years ended December 31, 2006, 2005 and 2004, the components of comprehensive income were as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Net income | $73,928 | $51,161 | $34,315 |
| Unrealized holding losses on derivative activities | (5,669) | (3,903) | — |
| Reclassification adjustment for derivative activities | 1,909 | (988) | — |
| Comprehensive income | $70,168 | $46,270 | $34,315 |

**16. 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 officers. 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—management and leasing of coal properties and subsequent collection of royalties; other land management activities such as selling standing timber and real estate rentals; leasing of fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants.
- Natural Gas Midstream—natural gas processing, natural gas gathering and other related services.

The following table presents a summary of certain financial information relating to our segments:

| | Coal | Natural Gas Midstream (1) | Consolidated |
|---|---|---|---|
| | | (in thousands) | |
| **For the year ended December 31, 2006** | | | |
| Revenues | $112,981 | $404,910 | $517,891 |
| Cost of midstream gas purchased | — | 334,594 | 334,594 |
| Operating costs and expenses | 19,138 | 23,846 | 42,984 |
| Depreciation, depletion and amortization | 20,399 | 17,094 | 37,493 |
| Operating income | $ 73,444 | $ 29,376 | 102,820 |
| Interest expense, net | | | (17,632) |
| Derivatives | | | (11,260) |
| Net income | | | $ 73,928 |
| Total assets | $409,709 | $304,314 | $714,023 |
| Equity investments | 25,295 | 60 | 25,355 |
| Additions to property, plant and equipment and acquisitions, net of cash acquired (2) | 92,697 | 37,015 | 129,712 |
| **For the year ended December 31, 2005** | | | |
| Revenues | $ 95,755 | $350,593 | $446,348 |
| Cost of midstream gas purchased | — | 303,912 | 303,912 |
| Operating costs and expenses | 16,121 | 17,597 | 33,718 |
| Depreciation, depletion and amortization | 17,890 | 12,738 | 30,628 |
| Operating income | $ 61,744 | $ 16,346 | 78,090 |
| Interest expense, net | | | (12,905) |
| 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 (3) | 96,862 | 206,811 | 303,673 |
| **For the year ended December 31, 2004** | | | |
| Revenues | $ 75,630 | $ — | $ 75,630 |
| Cost of midstream gas purchased | — | — | — |
| Operating costs and expenses | 16,479 | — | 16,479 |
| Depreciation, depletion and amortization | 18,632 | — | 18,632 |
| Operating income | $ 40,519 | $ — | 40,519 |
| Interest expense, net | | | (6,204) |
| 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 (4) | 1,088 | — | 1,088 |

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) Coal segment includes acquisition of assets other than property or equipment of $1.2 million.
(3) Coal segment excludes noncash expenditures of $14.4 million related to acquisitions.
(4) Excludes noncash expenditures of $1.1 million related to acquisitions.

Operating income is equal to total revenues less cost of midstream gas purchased, 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, 2006, two customers of the natural gas midstream segment accounted for approximately $129.1 million and $67.4 million, or 25% and 13%, of our consolidated net revenues. For the year ended December 31, 2005, two customers of the natural gas midstream segment accounted for $81.9 million and $77.1 million, or 18% and 17%, of our consolidated net revenues.

## 17. Quarterly Financial Information (Unaudited)

*Summarized Quarterly Financial Data*

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| | (in thousands except share data) | | | |
| ***2006*** | | | | |
| Revenues | $135,164 | $123,463 | $131,494 | $127,770 |
| Operating income | $ 18,246 | $ 29,289 | $ 29,898 | $ 25,387 |
| Net income (loss) | $ 8,340 | $ 13,221 | $ 31,339 | $ 21,028 |
| Basic and diluted net income (loss) per limited partner unit, common and subordinated (1) | $ 0.19 | $ 0.30 | $ 0.55 | $ 0.41 |
| Weighted average number of units outstanding, basic and diluted: | | | | |
| Common | 33,994 | 33,994 | 33,994 | 40,571 |
| Subordinated | 7,650 | 7,650 | 7,650 | 2,550 |
| ***2005 (2)*** | | | | |
| Revenues | $ 46,190 | $109,609 | $128,405 | $162,144 |
| Operating income | $ 14,300 | $ 20,436 | $ 22,496 | $ 20,858 |
| Net income (loss) | $ (2,471) | $ 16,865 | $ 22,370 | $ 14,397 |
| Basic and diluted net income (loss) per limited partner unit, common and subordinated (1) | $ (0.07) | $ 0.38 | $ 0.44 | $ 0.33 |
| Weighted average number of units outstanding, basic and diluted: | | | | |
| Common | 25,236 | 29,734 | 30,170 | 32,720 |
| Subordinated | 11,474 | 11,474 | 11,474 | 8,924 |

(1) 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 and due to applying the two-class method of calculating net income per limited partner unit (see Note 2).
(2) Includes the results of operations from the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.

**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, 2006. 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, 2006, 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, 2006. 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.

Our management has concluded that, as of December 31, 2006, our internal control over financial reporting was effective. KPMG LLP, an independent registered public accounting firm (or 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, 2006, which is included in Item 8 of this Annual Report or 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 2006 which we did not disclose.

## Part III

### Item 10 *Directors, Executive Officers and Corporate Governance*

### Directors and Executive Officers

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 PVG, its sole member and a majority-owned subsidiary of Penn Virginia.

| Name | Age | Position with our General Partner |
|---|---|---|
| A. James Dearlove | 59 | Chairman of the Board of Directors and Chief Executive Officer |
| Edward B. Cloues, II | 59 | Director |
| John P. DesBarres | 67 | Director |
| James L. Gardner | 55 | Director |
| James R. Montague | 59 | Director |
| Marsha R. Perelman | 56 | Director |
| Frank A. Pici | 51 | Director and Vice President and Chief Financial Officer |
| Nancy M. Snyder | 53 | Director and Vice President and General Counsel |
| Keith D. Horton | 53 | Co-President and Chief Operating Officer—Coal |
| Ronald K. Page | 56 | Co-President and Chief Operating Officer—Midstream |

*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 and as Chairman of the Board of Directors and Chief Executive Officer of PVG's general partner since September 2006. 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, a 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. Since 1996, Mr. DesBarres has been 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, a coal mining company. From 2000 to 2002, Mr. Gardner was in the private practice of law, principally representing Massey. Mr. Gardner served as Senior Vice President of Massey from 1994 to 2000 and as General Counsel from 1993 to 2000. From 1991 to 1993, Mr. Gardner was an attorney at the law firm of Hunton & Williams LLP.

*James R. Montague* has served as a director of our general partner since July 2001. Since 2003, Mr. Montague has been retired. 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 the non-executive Chairman of the Board of Davis Petroleum Corp., as a director of Atwood Oceanics, Inc. 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. Ms. Perelman also serves as a director of Penn Virginia.

*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 and as Vice President and Chief Financial Officer and as a director of PVG's general partner since September 2006. 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., or 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. From 1994 to 1996, Mr. Pici served as Corporate Controller of Cabot Oil & Gas Corporation, an oil and gas exploration and production company.

*Nancy M. Snyder* has served as Vice President and General Counsel and as a director of our general partner since July 2001 and as Vice President, General Counsel and Assistant Secretary and as a director of PVG's general partner since September 2006. Ms. Snyder has also served in various capacities with Penn Virginia since 1997, including as Executive Vice President since May 2006, as Senior Vice President from February 2003 to May 2006, as Vice President from December 2000 to February 2003 and as General Counsel and Corporate Secretary since 1997.

*Keith D. Horton* has served as Co-President and Chief Operating Officer—Coal of our general partner since June 2006 and as President of the Operating Company since September 2001. From July 2001 to June 2006, Mr. Horton served as President and Chief Operating Officer of our general partner. Mr. Horton has also served in various capacities with Penn Virginia since 1981, including as Executive Vice President since December 2000, as Vice President—Eastern Operations from February 1999 to December 2000 and as Vice President from February 1996 to February 1999. Mr. Horton also serves as a director of Penn Virginia and as director of the Virginia Mining Association, the Powell River Project and the Eastern Coal Council.

*Ronald K. Page* has served as Co-President and Chief Operating Officer—Midstream of our general partner since June 2006 and as President of PVR Midstream LLC since January 2005. From July 2003 to June 2006, Mr. Page served as Vice President, Corporate Development of our general partner. 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 from 2001 to 2003, Vice President of Business Development from 2000 to 2001 and Director of Business Development from 1999 to 2000.

**Role of the Board of Directors of our General Partner**

Our business is managed under the direction of the board of directors of our general partner. The board of directors of our general partner has adopted Corporate Governance Principles outlining its duties. A current copy of our general partner's Corporate Governance Principles is available at the "Governance" section of our website, http://www.pvresource.com, or in print upon request to Penn Virginia Resource GP, LLC, Attention: Secretary, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087. The board of directors of our general partner meets regularly to review significant developments affecting us and to act on matters requiring its approval.

**Code of Business Conduct and Ethics**

The board of directors of our general partner has adopted a Code of Business Conduct and Ethics as its "code of ethics" as defined in Item 406 of Regulation S-K, which applies to all directors, officers and employees of our general partner, including its Chief Executive Officer, Chief Financial Officer, principal accounting officer or controller or persons performing similar functions. A current copy of our general partner's Code of Business Conduct and Ethics is available at the "Governance" section of our website, http://www.pvresource.com, or in print upon request to Penn Virginia Resource GP, LLC, Attention: Secretary, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087, without charge.

**Executive Sessions and Meetings of Independent Directors; Communications with the Board**

Our general partner's Independent Directors, as such term is defined in "Item 13—Certain Relationships and Related Transactions, and Director Independence—Director Independence," 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.

**Committees of the Board of Directors of our General Partner**

The board of directors of our general partner has an audit committee, a conflicts committee and a compensation and benefits committee.

*Audit Committee.* Messrs. DesBarres, Gardner and Montague are the members of the audit committee of our general partner, and each such member is an Independent Director. Mr. DesBarres is an "audit committee financial expert" as defined in Item 407(d)(5) of Regulation S-K. 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 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 may obtain advice and assistance from outside legal, accounting or other advisors as it deems necessary to carry out its duties.

*Conflicts Committee.* Messrs. DesBarres, Gardner and Montague are the members of the conflicts committee of our general partner, and each such member is an Independent Director. The conflicts committee of our general partner reviews transactions between us and Penn Virginia, or any of its affiliates, including PVG, and any other transactions involving us or our affiliates that the board of directors of our general partner 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.

*Compensation and Benefits Committee.* Messrs. Cloues, DesBarres, Gardner and Montague are the members of the compensation and benefits committee of our general partner, and each such member is an Independent Director. The compensation and benefits committee of our general partner assists the compensation and benefits committee of Penn Virginia, or the Penn Virginia Committee, when the Penn Virginia Committee determines the compensation for the executive officers of our general partner. See "Item 11—Executive Compensation—Compensation Discussion and Analysis—How Compensation Is Determined—Committee Process." The committee reviews and discusses with management the information contained in Item 11, "Executive Compensation—Compensation Discussion and Analysis," and recommends that such information be included herein. The committee 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 the board of directors of our general partner. The committee also reviews and makes recommendations to the board of directors of our general 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 10% 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 2006 with the exception of one Form 4 of our general partner and one Form 4 of Penn Virginia, each of which was inadvertently filed one day late by us reporting the transfer of 42,698 restricted units to officers of our general partner pursuant to our general partner's long-term incentive plan.

## Item 11 *Executive Compensation*

### Compensation Discussion and Analysis

Under the rules established by the SEC, we are required to provide a discussion and analysis of information necessary to an understanding of our compensation policies and decisions regarding the Chief Executive Officer, or the CEO, Chief Financial Officer, or the CFO, and the other executive officers of our general partner named in the Summary Compensation Table included in this Annual Report on Form 10-K. The required disclosure includes the use of specified tables and a report of the compensation and benefits committee of our general partner. Unless otherwise indicated, all references in this Annual Report on Form 10-K to the "Named Executive Officers" refer to the executive officers named in the Summary Compensation Table, and all references to "our Committee" or the "Committee" refer to the compensation and benefits committee of our general partner.

### *Objectives of the Compensation Program*

Our compensation program is based on the following objectives:

- Executive compensation should be industry competitive so that we can attract, retain and motivate talented executives with appropriate experience and skill sets.
- Executives should be accountable for our performance as well as their own individual performance, so compensation should be tied to both partnership financial measures and individual performance measures.
- Executive compensation should balance and align the short-term and long-term interests of our executives with those of our unitholders, so executive compensation packages should include a mix of cash and equity-based compensation.

***Compensation Structure***

A. James Dearlove, Chief Executive Officer, Frank A. Pici, Vice President and Chief Financial Officer, and Nancy M. Snyder, Vice President and General Counsel, who are referred to in this Annual Report on Form 10-K as the "Shared Executives," rendered services to both Penn Virginia and us during 2006. We are responsible for paying only that portion of the Shared Executives' compensation related to the services they perform for us. The specific portions of salary and bonus paid by our general partner, on the one hand, and Penn Virginia, on the other hand, depend on the portion of professional time devoted by each Named Executive Officer to us and Penn Virginia. The Shared Executives are required to document the amount of professional time they spend rendering services to us and Penn Virginia. See "How Compensation Is Determined—Committee Process" for a discussion of our Committee's review of such allocations. Two of the Named Executive Officers, Keith D. Horton, Co-President and Chief Operating Officer—Coal of our general partner, and Ronald K. Page, Co-President and Chief Operating Officer—Midstream of our general partner, render their services solely to us so we pay 100% of their compensation.

In December 2006, PVG completed the PVG IPO. Beginning in 2007, the Shared Executives will devote some amount of their professional time to PVG, and PVG's general partner will be responsible for paying that portion of the Shared Executives' compensation related to the services they perform for PVG.

***Elements of Compensation***

We pay the Named Executive Officers a base salary and give them an opportunity to earn an annual cash bonus and an annual long-term compensation award. In determining these three elements of compensation, our Committee takes into account certain peer group information obtained by our Committee, the Penn Virginia Committee and each such committee's independent consultants, typically focusing on approximately the 50th percentile of the peer benchmarks described below under "How Compensation is Determined—Peer Benchmarks," but also applying its independent judgment to these matters and considering such other factors as it deems relevant. The three elements of compensation are:

- *Base Salary*—We pay each of the Named Executive Officers a base salary which our Committee has determined reflects his or her experience and capabilities and is industry competitive.
- *Annual Cash Bonus*—We give each of the Named Executive Officers the opportunity to earn an annual cash bonus. Our Committee and the Penn Virginia Committee generally target annual cash bonuses at an amount equal to 60% of base salary for the Named Executive Officers other than the CEO and 75% of base salary for the CEO, which our Committee believes is industry competitive. Our Committee and the Penn Virginia Committee recognize that annual cash bonuses could be higher or lower than the targeted amounts depending on actual Partnership, Penn Virginia or individual performance. Therefore, the actual amount of annual cash bonus, if any, awarded to each Named Executive Officer depends primarily on whether the performance criteria by which such officer is measured were met or exceeded. The performance criteria by which each Named Executive Officer is measured and other factors affecting the compensation of the Named Executive Officers are described below under the headings "Peer Benchmarks" and "Partnership, Company and Individual Performance Criteria." In addition to the performance criteria, our Committee and the Penn Virginia Committee may consider any other factors they deem appropriate when awarding annual cash bonuses to the Named Executive Officers.
- *Long-Term Compensation Awards*—We give each of the Named Executive Officers the opportunity to earn an annual long-term compensation award. Our Committee and the Penn Virginia Committee generally target annual long-term compensation awards at an amount equal to 120% of base salary for the Named Executive Officers other than the CEO and 150% of base salary for the CEO, which our Committee believes would be industry competitive. As with cash bonus awards, our Committee and the Penn Virginia Committee recognize that these annual long-term compensation awards could be higher or lower than the targeted amounts depending on whether actual Partnership, Penn Virginia or individual performance meets or exceeds applicable criteria. In addition to performance criteria, our

Committee and the Penn Virginia Committee may consider any other factors they deem appropriate when making long-term compensation awards to the Named Executive Officers. Long-term compensation awards are expressed in dollar values and our general partner or Penn Virginia pays those awards in the form of stock options, restricted stock or restricted units. The actual numbers of shares of restricted stock and restricted units awarded are based on the NYSE closing prices of Penn Virginia's common stock and our common units on the dates of grant. The actual number of stock options awarded is based on the value of the options on the date of grant using the Black-Scholes model. The Shared Executives' long-term compensation awards are split between restricted units of us, on the one hand, and stock options or restricted stock of Penn Virginia, on the other hand. For each Shared Executive, the ratio of the split between Partnership-related long-term compensation and Penn Virginia-related long-term compensation is determined based on the amount of time such Shared Executive devotes to each of us and Penn Virginia. Executives who render services wholly or predominately to us may receive only restricted units, and executives who render services wholly or predominantly to Penn Virginia may receive only stock options or restricted stock. Executives who receive Penn Virginia awards are given the opportunity to elect whether to receive those awards in stock options, restricted stock or a combination of both.

***How Compensation Is Determined***

***Committee Process***. Penn Virginia indirectly controls our general partner and owns 100% of our incentive distribution rights and a significant limited partner interest in us. Because of this relationship, and since all of the Named Executive Officers are also executives of Penn Virginia and three of the Named Executive Officers, including the CEO, devote a significant amount of their professional time to Penn Virginia, the Penn Virginia Committee sets compensation for the Named Executive Officers. Our Committee assists the Penn Virginia Committee in determining executive compensation for the Named Executive Officers in the manner described below. Both our Committee and the Penn Virginia Committee are comprised entirely of Independent Directors.

With respect to Messrs. Horton and Page, who manage our coal-related and midstream-related operations, respectively, and devote substantially all of their business time to us and who are referred to in this Annual Report on Form 10-K as the "Partnership Executives," our Committee has the primary responsibility to assess all factors relevant to their compensation and, based on that assessment, recommend to the Penn Virginia Committee salary, annual cash bonus and long-term compensation awards for them. Since the Partnership Executives report directly to, and work on a daily basis with, the CEO, our Committee reviews and discusses with the CEO his evaluation of the performance of each of the Partnership Executives prior to making its recommendation regarding their compensation, and our Committee gives the CEO's evaluations considerable weight in assessing the amount of compensation to recommend to the Penn Virginia Committee for the Partnership Executives. The CEO bases his evaluation of each of the Partnership Executives primarily on whether we met or exceeded certain quantitative partnership performance criteria and whether such Partnership Executive met or exceeded certain specifically tailored job-related individual performance criteria recommended by the CEO and our Committee and set by the Penn Virginia Committee during the preceding year. These performance criteria and other factors relevant to the Partnership Executives' compensation are described in detail below under the headings "Peer Benchmarks" and "Partnership, Company and Individual Performance Criteria." The Penn Virginia Committee then considers the CEO's and our Committee's recommendations as well as other factors it deems relevant and makes the final determination regarding the compensation of each of the Partnership Executives. The Penn Virginia Committee set the 2007 base salaries and 2006-related long-term compensation awards for each of the Partnership Executives in the amounts our Committee recommended.

With respect to the Shared Executives, including the CEO, the Penn Virginia Committee assesses the factors relevant to, and determines, their compensation. Our Committee reviews and discusses such assessment with the Penn Virginia Committee and determines whether it believes such assessment is reasonable. Since the Shared Executives other than the CEO report directly to, and work on a daily basis with, the CEO, the Penn Virginia Committee reviews and discusses with the CEO his evaluation of the performance of each of the other Shared

Executives, and gives considerable weight to the CEO's evaluations, when assessing their performance and determining their compensation. The Penn Virginia Committee bases its evaluation of the CEO, and the CEO bases his evaluation of each of the other Shared Executives, primarily on whether we or Penn Virginia met or exceeded certain quantitative partnership or corporate performance criteria and whether each Shared Executive met or exceeded certain specifically tailored job-related individual performance criteria recommended by the CEO and set by the Penn Virginia Committee during the preceding year. These performance criteria and other factors relevant to the Shared Executives' compensation are described in detail below under the headings "Peer Benchmarks" and "Partnership, Company and Individual Performance Criteria." Since the amount of the Shared Executives' compensation we pay depends on the amount of professional time they devote to us, our Committee and the audit committee of our general partner review the allocation of the Shared Executives' time between us and Penn Virginia and determines whether such allocations are reasonable.

***Peer Benchmarks.*** In 2004, the Penn Virginia Committee and our Committee engaged an independent consultant to assist both committees in a general review of the compensation packages for Penn Virginia's and our executive officers. The independent consultant used three peer groups, or the Peer Benchmarks, to benchmark the compensation of our five most highly compensated executives—Penn Virginia's proxy peers, a second general industry group derived from the consultant's database and comprised of companies with 2004 revenues comparable to Penn Virginia's 2004 revenues and a third general energy industry group with 2004 revenues comparable to Penn Virginia's, which was derived from the database of a second independent compensation consulting firm. Using the information obtained from the independent consultant, and given our Committee's and the Penn Virginia Committee's belief that executives should have the opportunity to earn industry competitive compensation, in February 2005, our Committee and the Penn Virginia Committee decided to target each component of executive compensation at approximately the 50th percentile of the Peer Benchmarks and established the framework described herein to determine the actual amounts of such components. Our Committee and the Penn Virginia Committee continued to use the Peer Benchmarks to assess, recommend or set executive salaries for 2006 and 2007 and cash bonuses and long-term compensation awards payable with respect to 2005 and 2006 even though Penn Virginia's 2004 revenues were an important factor in establishing the Peer Benchmarks and those revenues increased substantially in 2005 and 2006. To keep industry compensation reviews current, the Penn Virginia Committee and our Committee each engaged an independent consultant to review the compensation to be paid to the Named Executive Officers in 2007 and paid to the Named Executive Officers in and with respect to 2006. These independent consultants reported that the salaries paid to the Named Executive Officers in 2007 and 2006, and the annual cash bonuses and long-term compensation awards paid to the Named Executive Officers with respect to 2006, were generally consistent with peer companies and industry practice.

***Partnership, Company and Individual Performance Criteria.*** The Penn Virginia Committee, with the assistance of our Committee, targets the amount of salary, cash bonus and long-term compensation award for each Named Executive Officer at approximately the 50th percentile of the Peer Benchmarks with respect to each of those elements. However, given the importance of executive accountability for our and Penn Virginia's performance as well as for individual performance, our Committee and the Penn Virginia Committee recognize that compensation for any Named Executive Officer could exceed such 50th percentile targets, reflecting a reward for exceptional Partnership, Penn Virginia or individual performance, or be lower than such 50th percentile targets, reflecting Partnership, Penn Virginia or individual underperformance, with a range of the 35th to the 65th percentile being considered for this purpose to be approximately the 50th percentile. To measure specific performance, our Committee and the Penn Virginia Committee use certain quantitative Partnership and Penn Virginia performance criteria and certain quantitative and qualitative individual performance criteria which measure achievement and contribution to us or Penn Virginia. Our Committee and the Penn Virginia Committee believe that these performance criteria are focused on factors over which the Named Executive Officers have some control and which should have a positive effect on our and Penn Virginia's operations and the price of our common units or Penn Virginia's common stock. The weight given any one criterion and the mix of criteria included in determining amounts of compensation vary among the Named Executive Officers depending on their positions and principal areas of responsibility. The relevance and the relative importance of any of these criteria change from time to time, even within the same year, depending on our and Penn Virginia's strategic objectives, operational needs and general business and regulatory environments. For this reason, our Committee and the Penn Virginia Committee may change these performance criteria from year to year, may assign an aggregate weight to several performance criteria applicable to a Named Executive Officer or may consider additional criteria which were not known at the time the original criteria were established.

*Partnership and Company Performance Criteria for Shared Executives.* Messrs. Dearlove and Pici and Ms. Snyder generally provide services to, and make executive decisions and direct policy for, both us and Penn Virginia in ways that directly affect our and Penn Virginia's financial and other results. For this reason, the Penn Virginia Committee tied the Shared Executives' annual cash bonuses and long-term compensation awards for 2006 to the following quantitative financial corporate and partnership performance criteria:

- Growth in Penn Virginia's net asset value per share from December 31, 2005 to December 31, 2006. "Net asset value per share," as we and Penn Virginia compute it, is equal to (x) the value of its proved oil and natural gas reserves and other assets (principally, the market value of its ownership interest in PVG, its publicly-traded majority-owned subsidiary through which it owns its general and limited partner interests in us), less (y) its debt not related to us, divided by (z) the total number of shares of its common stock issued and outstanding.
- Growth in our distributable cash flow per unit from December 31, 2005 to December 31, 2006. "Distributable cash flow per unit," as we and Penn Virginia compute it, is equal to (x) the sum of our (A) operating income plus (B) depreciation, depletion and amortization, or DD&A, minus (y) the sum of our (A) interest expense plus (B) maintenance capital expenditures, divided by (z) the total number of our common units issued and outstanding.

The Penn Virginia Committee set the targets for growth in its net asset value per share and our distributable cash flow per unit at levels slightly above the amounts for these targets that were included in our and Penn Virginia's 2006 board-approved budgets. Since neither we nor Penn Virginia budget for acquisitions, our Committee and the Penn Virginia Committee believed that it would be challenging for Penn Virginia or us to achieve through organic growth alone sufficient increases in net asset value per share or distributable cash flow per unit to meet these criteria. These criteria would likely be met if Penn Virginia or we completed a significant acquisition.

*Individual Performance Criteria for Shared Executives.* In addition to working together and with the other Named Executive Officers to manage us and Penn Virginia generally, Messrs. Dearlove and Pici and Ms. Snyder have distinct job-related responsibilities to us and Penn Virginia and, accordingly, their compensation for 2006 was also based on specific individual performance criteria as follows:

- A. James Dearlove—Mr. Dearlove's 2006 individual performance criteria were as follows:
  - Continually assess and modify our and Penn Virginia's strategy as needed to accommodate changes in the energy and general business environments.
  - Evaluate, recommend and oversee the consummation of (i) the PVG IPO, (ii) a significant acquisition for us and (iii) a significant acquisition for Penn Virginia.
  - Appoint and continually develop management and other key employees of our general partner and Penn Virginia who will facilitate our and Penn Virginia's future growth.
  - Represent us and Penn Virginia to the public through teleconferences, conferences and shareholder, unitholder and other meetings.
  - Ensure an ethical "tone at the top" regarding compliance by us and Penn Virginia with all applicable laws, rules and regulations.

  In February 2007, the Penn Virginia Committee, with our Committee's assistance, set Mr. Dearlove's base salary at $380,000, representing a 3.5% increase over his 2006 base salary. In 2004, the independent compensation consultant retained by our Committee and the Penn Virginia Committee had found that Mr. Dearlove's 2004 base salary was significantly below that of CEOs at the 50% percentile of the Peer Benchmarks. Since the Penn Virginia Committee has approved only a 3.5% to 4.0% salary increase for Mr. Dearlove in each year since 2004, his 2007 salary most likely continues to be non-competitive. However, in February 2007, the Penn Virginia Committee, with our Committee's assistance, also awarded to Mr. Dearlove a cash bonus of $370,000, or 100% of his 2006 base salary, and a long-term compensation award valued at $625,000, or 170% of his base salary. The decision to make bonus and long-term compensation awards to Mr. Dearlove in these amounts was based on the fact that, in 2006, the growth in our distributable cash flow per unit and Penn Virginia's net asset value per share significantly surpassed the targets for such criteria established by the Penn Virginia Committee. In addition, the Penn Virginia Committee, with our Committee's assistance, determined that Mr. Dearlove exceeded expectations related to his 2006 individual performance criteria described above, most notably by recommending and overseeing the evaluation and consummation of the PVG IPO, overseeing three coal reserve acquisitions, or the Coal Acquisitions, whereby our coal division acquired an aggregate of approximately 96 million tons of coal reserves, overseeing the strategically important acquisition by our midstream division of the Transwestern pipeline, or the Transwestern Acquisition, which, among other things, significantly expanded our midstream division's gas gathering and processing footprint in Texas and Oklahoma, and overseeing the expansion of Penn Virginia's oil and gas exploration and production business into a new growth-enhancing basin through the acquisition of $71.5 million worth of Mid-Continent oil and gas assets, which we refer to as the "Mid-Continent Acquisition." Our Committee and the Penn Virginia Committee believe that these amounts of cash bonus and long-term compensation, when combined with base salary, comprise an industry competitive compensation package and appropriately reflect our, Penn Virginia's and Mr. Dearlove's 2006 performance. In December 2006, the Penn Virginia Committee also awarded Mr. Dearlove 4,000 PVG common units in recognition of services rendered in connection with the PVG IPO, which was completed on December 8, 2006.

- Frank A. Pici—Mr. Pici's 2006 individual performance criteria were as follows:
  - Evaluate and direct the financial advisors retained in connection with the PVG IPO.
  - Recommend and execute a hedging policy for each of our natural gas midstream business and Penn Virginia's oil and gas exploration and production business which is consistent with our general partner's and Penn Virginia's board-approved strategic objectives.
  - Oversee the installation of a new core accounting system.
  - Oversee Sarbanes-Oxley Act compliance and financial reporting requirements and manage our general partner's and Penn Virginia's internal audit, information technology, investor relations, treasury and tax functions.
  - Increase analyst coverage for us and Penn Virginia.

  In February 2007, the Penn Virginia Committee, with our Committee's assistance, set Mr. Pici's base salary at $263,000, representing a 4.0% increase over his 2006 base salary. In February 2007, the Penn Virginia Committee, with our Committee's assistance, also awarded Mr. Pici a cash bonus of $205,000, or 81% of his 2006 base salary, and a long-term compensation award valued at $380,000, or 150% of his 2006 base salary. The decision to make bonus and long-term compensation awards to Mr. Pici in these amounts was based on the fact that, as discussed above, the 2006 growth in our distributable cash flow per unit and Penn Virginia's net asset value per share significantly surpassed the targets established for such criteria by the Penn Virginia Committee. In addition, the Penn Virginia Committee, with our Committee's assistance, determined that Mr. Pici exceeded expectations related to his 2006 individual performance criteria, most notably through his work related to the PVG IPO, overseeing the financial evaluations of the Coal Acquisitions, the Transwestern Acquisition and the Mid-Continent Acquisition and identifying and overseeing the on-going integration of a new core accounting system. In December 2006, the Penn Virginia Committee also awarded Mr. Pici 4,000 PVG common units in recognition of services rendered in connection with the PVG IPO.

- Nancy M. Snyder—Ms. Snyder's 2006 individual performance criteria were as follows:
  - Evaluate the structural and legal issues related to, and direct the legal and other advisors retained in connection with, the PVG IPO.
  - Negotiate issues related to our and Penn Virginia's acquisitions, dispositions and other transactions.
  - Advise us and Penn Virginia with respect to business and strategic transactional issues.
  - Advise and assist other officers of our general partner and Penn Virginia with respect to day-to-day legal matters, including those related to banking, insurance, contracts, potential acquisitions and dispositions and tax.
  - Oversee compliance with all applicable rules and regulations, including Sarbanes-Oxley Act and other SEC and NYSE rules and regulations, and monitor changes in such rules and regulations.
  - Oversee outside legal counsel, in-house legal staff and the corporate secretary function.

  In February 2007, the Penn Virginia Committee, with our Committee's assistance, set Ms. Snyder's 2007 base salary at $230,000, representing a 4.5% increase over her 2006 base salary. In addition, in February 2007, the Penn Virginia Committee, with our Committee's assistance, awarded Ms. Snyder a cash bonus of $180,000, or 82% of her 2006 base salary, and a long-term compensation award valued at $330,000, or 150% of her 2006 base salary. The decision to make awards of these amounts to Ms. Snyder was based on us and Penn Virginia significantly surpassing our and Penn Virginia's target criteria for 2006 growth in distributable cash flow per unit and net asset value per share. In addition, the Penn Virginia Committee, with our Committee's assistance, determined that Ms. Snyder exceeded expectations related to her individual performance criteria, most notably through her work related to the PVG IPO, the Coal Acquisitions, the Transwestern Acquisition and the Mid-Continent Acquisition. In December 2006, the Penn Virginia Committee also awarded Ms. Snyder 4,000 PVG common units in recognition of services rendered in connection with the PVG IPO.

*Performance Criteria for Partnership Executives.* Messrs. Horton and Page provide services to, and make executive decisions and direct policy for, us in ways that directly affect our operational and financial results and indirectly affect Penn Virginia's financial results. Accordingly, their compensation is based on specific Partnership and individual performance criteria as follows:

- Keith D. Horton—Our Committee tied its compensation assessment and recommendation to the Penn Virginia Committee, and the Penn Virginia Committee tied its review of our Committee's recommendation and its final determination, regarding Mr. Horton's 2006 compensation to the following Partnership and individual performance criteria related to our coal land management business, which is the specific segment of our business managed by him:
  - Increase in our coal-related EBITDA from December 31, 2005 to December 31, 2006. We and Penn Virginia define coal-related EBITDA as the sum of coal segment-related (x) operating income plus (y) DD&A.
  - Increase in our coal reserves from December 31, 2005 to December 31, 2006.
  - Increase in revenues from assets other than coal reserves, such as railcar loading facilities, processing plants and other coal infrastructure and timber, from December 31, 2005 to December 31, 2006.
  - Develop long range plans to acquire non-Central Appalachian coal.
  - Develop long range plans to grow non-coal reserve revenues.

  Our Committee recommended, and the Penn Virginia Committee set, the targets for growth in coal-related EBITDA, coal reserves and non-coal reserve revenues at levels slightly above the amounts for these targets that were included in our 2006 board-approved budget. Since we do not budget for acquisitions, our Committee and the Penn Virginia Committee believed that it would be challenging for us to achieve through organic growth alone sufficient increases in the criteria set forth in the first three bullet points above. These criteria would likely be met if we completed a significant coal acquisition.

Our Committee recommended, and the Penn Virginia Committee set, Mr. Horton's 2007 base salary at $270,000, representing a 3.8% increase over his 2006 base salary. In addition, our Committee recommended and, in February 2007, the Penn Virginia Committee, with the concurrence of our Committee, awarded Mr. Horton a cash bonus of $182,000, or 70% of this 2006 base salary, and a long-term compensation award valued at $315,000, or 121% of his 2006 base salary. The decisions to recommend and make bonus and long-term compensation awards to Mr. Horton in these amounts were based on the fact that growth in our 2006 coal-related EBITDA, which our Committee and the Penn Virginia Committee believe is the most important criterion related to Mr. Horton's compensation, and growth in our non-coal reserve revenues surpassed the targets recommended by our Committee and established by the Penn Virginia Committee for such criteria. In addition, our Committee and the Penn Virginia Committee considered Mr. Horton's role in developing a long-range plan to acquire non-Central Appalachian coal reserves. In December 2006, the Penn Virginia Committee also awarded Mr. Horton 1,500 PVG common units in recognition of services rendered in connection with the PVG IPO.

- Ronald K. Page—Our Committee tied its compensation assessment and recommendation to the Penn Virginia Committee, and the Penn Virginia Committee tied its review of our Committee's recommendation and its final determination, regarding Mr. Page's 2006 compensation to the following Partnership and individual performance criteria related to our natural gas midstream business, which is the specific segment of our business managed by him:
  - Increase in our midstream-related EBITDA from December 31, 2005 to December 31, 2006. We and Penn Virginia define midstream-related EBITDA as the sum of midstream segment-related (x) operating income plus (y) DD&A.
  - Identify and evaluate midstream assets in new core areas.
  - Contribute to the establishment and execution of a hedging policy.
  - Develop better reporting and analysis tools, restructure midstream contracts to increase earnings stability and expand existing facilities.
  - Evaluate joint venture acquisition and other opportunities with Penn Virginia Oil and Gas Corporation, Penn Virginia's oil and gas exploration and production affiliate, and other others.
  - Develop long range plans for targeted growth objectives and possible diversification.

  Our Committee also recommended, and the Penn Virginia Committee set, the target for growth in midstream-related EBITDA at a level slightly above the amount for this target that was included in our 2006 board-approved budget. Since we do not budget for acquisitions, our Committee and the Penn Virginia Committee believed that it would be challenging for us to achieve through organic growth alone a sufficient increase in midstream-related EBITDA to meet this criterion. This criterion would likely be met if we completed a significant natural gas midstream acquisition.

  Our Committee recommended and the Penn Virginia Committee set Mr. Page's 2007 base salary at $235,000, representing a 6.8% increase over his 2006 base salary. In addition, our Committee recommended and, in February 2007, the Penn Virginia Committee, with the concurrence of our Committee, awarded Mr. Page a cash bonus of $150,000, or 68% of his 2006 base salary, and a long-term compensation award valued at $265,000, or 120% of his 2006 base salary. The decisions to recommend and make bonus and long-term compensation awards to Mr. Page in these amounts were based on the fact that the 2006 growth in our midstream-related EBITDA, which our Committee and the Penn Virginia Committee believe is the most important criterion related to Mr. Page's compensation, significantly surpassed the target established for such criterion. In addition, our Committee and the Penn Virginia Committee considered Mr. Page's roles in overseeing the evaluation and consummation of the Transwestern Acquisition, the restructuring of our midstream division's contracts and the establishment and execution of a new hedging policy for our midstream division. In December 2006, the Penn Virginia Committee also awarded Mr. Page 1,500 PVG common units in recognition of services rendered in connection with the PVG IPO.

### Summary Compensation Table

The following table sets forth the compensation paid by our general partner, during or with respect to the year ended December 31, 2006, to the CEO, the CFO and our general partner's three other most highly compensated executive officers for services rendered to us and our subsidiaries.

**Summary Compensation Table**

| Name and Principal Position | Year | Salary ($) | Bonus ($) | Stock Awards ($) (1) | All Other Compensation ($) (2) | Total ($) |
|---|---|---|---|---|---|---|
| A. James Dearlove<br>*Chief Executive Officer* | 2006 | 183,500 | 185,000 | 253,348 | 19,024 | 640,872 |
| Frank A. Pici<br>*Vice President and Chief Financial Officer* | 2006 | 80,960 | 65,600 | 125,175 | 10,200 | 281,935 |
| Keith D. Horton<br>*Co-President and Chief Operating Officer—Coal* | 2006 | 260,000 | 182,000 | 261,957 | 32,528 | 736,485 |
| Ronald K. Page<br>*Co-President and Chief Operating Officer—Midstream* | 2006 | 220,000 | 150,000 | 151,644 | 32,104 | 553,748 |
| Nancy M. Snyder<br>*Vice President and General Counsel* | 2006 | 94,600 | 77,400 | 110,444 | 13,987 | 296,431 |

(1) Represents the amounts of expense recognized by us in 2006 for financial statement reporting purposes with respect to restricted units previously granted by our Committee to the Named Executive Officers in consideration for services rendered to us. These amounts were computed in accordance with Financial Accounting Standards (FAS) 123R and were based on the NYSE closing price of our common units on the dates of grant. See Note 13 in the Notes to Consolidated Financial Statements.

(2) Reflects amounts paid or reimbursed by our general partner for (i) automobile allowances, executive health exams and life insurance premiums and (ii) matching and other contributions to the Named Executive Officers' 401(k) Plan accounts.

The cash components of our executive compensation consist of a base salary and the opportunity to earn an annual cash bonus. See "Compensation Discussion and Analysis—Elements of Compensation." The amounts of salary and bonus reflected in the Summary Compensation Table above include only amounts paid by our general partner to the Named Executive Officers in consideration for services rendered to us and do not include any amounts paid by Penn Virginia to any of the Named Executive Officers in consideration for services rendered to Penn Virginia. The specific portions of salary and bonus paid by our general partner, on one hand, and Penn Virginia, on the other hand, depend on the portion of professional time devoted by each Named Executive Officer to us and Penn Virginia. See "Compensation and Discussion Analysis—Compensation Structure" for a description of the manner in which the Named Executive Officers are compensated. In 2006, Mr. Dearlove, Mr. Pici and Ms. Snyder devoted approximately 50%, 32% and 43% of his or her professional time to us and, accordingly, our general partner reimbursed Penn Virginia for 50%, 32% and 43% of Mr. Dearlove's, Mr. Pici's and Ms. Snyder's 2006 salary and 2006-related bonus. Because each of the Partnership Executives devoted all of his professional time to us in 2006, our general partner paid 100% of his 2006 salary and 2006-related bonus. For a discussion of the salaries and bonuses paid to the Shared Executives by Penn Virginia, see the Penn Virginia Proxy Statement relating to its 2007 Annual Meeting of Shareholders.

The equity components of our executive compensation consist of the opportunity to earn awards of restricted units from us and stock options and restricted stock from Penn Virginia. Like the cash component of executive compensation, that portion of the value of each Named Executive Officer's equity-based compensation paid by our general partner depends on the portion of professional time that the Named Executive Officer devotes to us. The values of the stock awards reflected in the Summary Compensation Table above include only the values of restricted unit awards granted by our Committee. Each Shared Executive devoted approximately 50% of his or her time to each of us and Penn Virginia in 2005. Consequently, in 2006, our Committee granted to each Shared Executive restricted units with respect to services rendered in 2005 valued at approximately 50% of the total long-term compensation earned by him or her. Our Committee granted all equity awards made to the Partnership Executives in 2006.

### Grants of Plan-Based Awards

The following table sets forth the grant date and number of all restricted units granted to the Named Executive Officers in 2006 by our Committee with respect to services rendered to us in 2005.

**2006 Grants of Plan-Based Awards**

| Name | Grant Date | All Other Stock Awards: Number of Shares of Stock or Units (#) | Grant Date Fair Value of Stock and Option Awards ($) |
|---|---|---|---|
| A. James Dearlove | February 27, 2006 | 10,070 | 291,023 |
| Frank A. Pici | February 27, 2006 | 6,090 | 176,001 |
| Keith D. Horton | February 27, 2006 | 12,110 | 349,979 |
| Ronald K. Page | February 27, 2006 | 9,342 | 269,983 |
| Nancy M. Snyder | February 27, 2006 | 5,086 | 146,985 |

The values of our restricted units were based on the NYSE closing price of our common units on the dates of grant. All restricted units granted to the Named Executive Officers since 2005 vest over a three-year period, with one-third of each award vesting on the first, second and third anniversaries of the grant date unless (i) our general partner terminates the restricted unitholder's employment for cause, in which event such restricted units are forfeited, or (ii) the restricted unitholder dies, retires after ten years of employment with our general partner or its affiliate and reaching age 62 or there occurs a change in control of our general partner, in which events all restrictions lapse. All restricted units granted to the Named Executive Officers prior to 2005 vested 25% on November 12, 2004, 25% on November 14, 2005 and 50% on November 14, 2006. The vesting of the pre-2005 restricted units was tied to the vesting of certain of our subordinated units issued to Penn Virginia in connection with our initial public offering in October 2001. Restricted units are valued based on the NYSE closing price of our common units on the grant date. Our Committee grants annual compensation-based restricted units during the first quarter of each year after the Penn Virginia Committee, with our Committee's assistance, has concluded its analysis of executive compensation with respect to the preceding year. Our Committee also grants restricted units from time to time in connection with the hiring of new Partnership-related employees and, while it has not done so, may consider such grants in connection with promotions. During 2006, we paid quarterly distributions ranging from $0.35 to $0.40 on each restricted unit. The distributions were paid at the same times and in the same amounts as distributions paid to the other holders of our common units and were taken into consideration when determining the values of the restricted units shown previously in the Summary Compensation Table and in the Grants of Plan-Based Awards Table above.

## Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding the numbers and values of restricted units not vested as of December 31, 2006 held by the Named Executive Officers on December 31, 2006. The market value of non-vested restricted units is based on the NYSE closing price of our common units on December 29, 2006.

**Outstanding Equity Awards at Fiscal Year-End 2006**

| | Stock Awards | |
|---|---|---|
| Name | Number of Shares or Units of Stock That Have Not Vested (#) | Market Value of Shares or Units of Stock That Have Not Vested ($) |
| A. James Dearlove | 15,906 (1) | 413,715 |
| Frank A. Pici | 9,522 (2) | 247,667 |
| Keith D. Horton | 18,044 (3) | 469,324 |
| Ronald K. Page | 14,246 (4) | 370,538 |
| Nancy M. Snyder | 8,028 (5) | 208,808 |

(1) Of these restricted units, 3,358 vested on February 27, 2007, 2,918 will vest on March 3, 2007, 3,356 will vest on February 27, 2008, 2,918 will vest on March 3, 2008 and 3,356 will vest on February 27, 2009.

(2) Of these restricted units, 2,030 vested on February 27, 2007, 1,716 will vest on March 3, 2007, 2,030 will vest on February 27, 2008, 1,716 will vest on March 3, 2008 and 2,030 will vest on February 27, 2009.

(3) Of these restricted units, 4,038 vested on February 27, 2007, 2,968 will vest on March 3, 2007, 4,036 will vest on February 27, 2008, 2,966 will vest on March 3, 2008 and 4,036 will vest on February 27, 2009.

(4) Of these restricted units, 3,114 vested on February 27, 2007, 2,452 will vest on March 3, 2007, 3,114 will vest on February 27, 2008, 2,452 will vest on March 3, 2008 and 3,114 will vest on February 27, 2009.

(5) Of these restricted units, 1,696 vested on February 27, 2007, 1,472 will vest on March 3, 2007, 1,696 will vest on February 27, 2008, 1,470 will vest on March 3, 2008 and 1,694 will vest on February 27, 2009.

## Vesting of Restricted Units

The following table sets forth the number of common units acquired, and the values realized, by the Named Executive Officers upon the vesting of restricted units during 2006.

**Option Exercises and Stock Vested in 2006**

| | Stock Awards | |
|---|---|---|
| Name | Number of Shares Acquired on Vesting (#) | Value Realized on Vesting ($) |
| A. James Dearlove | 16,118 | 413,659 |
| Frank A. Pici | 7,218 | 187,232 |
| Keith D. Horton | 16,968 | 434,972 |
| Ronald K. Page | 3,700 | 103,566 |
| Nancy M. Snyder | 6,972 | 179,946 |

## Nonqualified Deferred Compensation

The following table sets forth certain information regarding compensation paid by both our general partner and Penn Virginia and deferred by the Named Executive Officers under Penn Virginia's Supplemental Employee Retirement Plan.

**2006 Nonqualified Deferred Compensation**

| Name | Executive Contributions in Last FY ($) (1) | Registrant Contributions in Last FY ($) | Aggregate Earnings in Last FY ($) (2) | Aggregate Withdrawals/ Distributions ($) | Aggregate Balance at Last FYE ($) |
|---|---|---|---|---|---|
| A. James Dearlove | 20,115 | 0 | 29,838 | 0 | 370,728 |
| Frank A. Pici | 403,057 | 0 | 126,571 | 0 | 1,245,255 |
| Keith D. Horton | 1,153 | 0 | 1,843 | 0 | 17,020 |
| Ronald K. Page | 12,688 | 0 | 2,307 | 0 | 35,022 |
| Nancy M. Snyder | 175,877 | 0 | 105,479 | 0 | 779,958 |

(1) Except with respect to aggregate Penn Virginia contributions of $22,921 on behalf of Mr. Pici in 2001 and 2002, all of these amounts are included in the amounts of salary and bonus disclosed by us or Penn Virginia in the Summary Compensation Tables included in our Annual Reports on Form 10-K and Penn Virginia's Proxy Statements.

(2) These amounts are not reported in any Summary Compensation Table because they are not above-market or preferential earnings.

The Penn Virginia Corporation Supplemental Employee Retirement Plan, or the SERP, allows all of Penn Virginia's and its affiliates' employees, including employees of our general partner, whose salaries exceeded $125,000 in 2006 to defer receipt of up to 100% of their salary, net of their salary deferrals under Penn Virginia's 401(k) Plan, and up to 100% of their annual cash bonuses. The amounts reported in the Nonqualified Deferred Compensation Table above include not only contributions and earnings thereon related to deferred salaries and bonuses paid for services rendered to us, but also contributions and earnings thereon related to deferred salaries and bonuses paid for services rendered to Penn Virginia. All deferrals under the SERP are credited to an account maintained by Penn Virginia and are invested by Penn Virginia, at the employee's election, in Penn Virginia's common stock or in certain mutual funds made available by Penn Virginia and selected by the employee. Since all amounts deferred under the SERP consist of previously earned salary or bonus, all SERP participants are fully vested at all times in all amounts credited to their accounts. Amounts held in a participant's account will be distributed to the participant on the earlier of the date on which such participant's employment terminates or there occurs a change of control of Penn Virginia. Neither we nor Penn Virginia are required to make any contributions to the SERP. Since Penn Virginia established the SERP in 1996, it has contributed an aggregate of $27,308 in 2001 and 2002 to the SERP in connection with offers of employment to Mr. Pici and another executive of Penn Virginia, but has made no other contributions to the SERP.

Penn Virginia has established a rabbi trust to fund the benefits payable under the SERP. Other than the $27,308 of Penn Virginia contributions described above, the assets of the rabbi trust consist of the cash amounts of salary and bonus already earned and deferred by the Named Executive Officers and other employees under the SERP and the securities in which those amounts have been invested. Assets held in the rabbi trust are designated for the payment of benefits under the SERP and are not available for Penn Virginia's general use. However, the assets held in the rabbi trust are subject to the claims of Penn Virginia's general creditors, and SERP participants may not be paid in the event of Penn Virginia's insolvency.

## 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 600,000 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 our Committee.

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 81,906 restricted units to officers and employees of our general partner in 2006. Restricted units vest upon terms established by our committee. In addition, all restricted units will vest upon a change of control of our general partner or us. 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 our Committee provides otherwise. Distributions payable with respect to restricted units may, in our 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 our 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 our Committee. In addition, all unit options will become exercisable upon a change in control of our general partner or us. 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 our 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 our 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. Our 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 us. 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, our 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. Our 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 24,189 deferred common units to directors of our general partner in 2006. 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 additional deferred common units equal in value to all cash or other distributions paid by us on account of our common units.

**Change-in-Control Arrangements**

*General Partner Executive Change of Control Severance Agreements*

On March 9, 2006, our general partner entered into an Executive Change of Control Severance Agreement, or a General Partner Severance Agreement, with each of Messrs. Horton and Page 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 Partnership Executive upon the occurrence of two events, or 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 Partnership Executive's employment is terminated for any reason other than for cause or the Partnership Executive's inability to perform his duties for at least 180 days due to mental or physical impairment or (b) the Partnership 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 Partnership 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 Partnership 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 shares of Penn Virginia common stock then held by the Partnership 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 the Partnership Executive will immediately vest and all restrictions will lapse. Our general partner will also provide certain health and dental benefit related payments to the Partnership 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 Partnership 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.

*Restrictive Covenants.* The General Partner Severance Agreement prohibits the Partnership Executive from (a) disclosing, either during or after his term of employment, confidential information regarding our general partner or its affiliates and (b) until two years after his employment has ended, soliciting or diverting business from our general partner or its affiliates. The General Partner Severance Agreement also requires that, upon payment of the severance benefits to the Partnership Executive, the Partnership Executive and our general partner release each other from all claims relating to the Partnership Executive's employment or the termination of such employment.

*Estimated Payments*

The following table sets forth the estimated aggregate payments by our general partner to each of Messrs. Horton and Page under his General Partner Severance Agreement assuming that there occurred a change of control of our general partner on December 31, 2006.

| Name of Executive Officer | Estimate Severance Payment ($) |
|---|---|
| Keith D. Horton | 2,007,164 |
| Ronald K. Page | 1,708,493 |

*Penn Virginia Executive Change of Control Severance Agreements*

On February 27, 2006, Penn Virginia entered into an Executive Change of Control Severance Agreement, or a Penn Virginia Severance Agreement, with each of the Shared Executives containing terms and conditions substantially similar to those of the General Partner Severance Agreements. For a discussion of the terms and conditions of, and the estimated payments under, the Penn Virginia Severance Agreements, see the Penn Virginia Proxy Statement relating to its 2007 Annual Meeting of Shareholders. Any payments required to be made to the Shared Executives under the Penn Virginia Severance Agreements will be the sole responsibility of Penn Virginia.

## Compensation of Directors

The following table sets forth the aggregate compensation paid by us to the non-employee directors of our general partner during 2006.

**2006 Director Compensation**

| Name | Fees Earned or Paid in Cash ($) | Stock Awards ($) (1) | Total ($) |
|---|---|---|---|
| Edward B. Cloues, II | 36,000 | 90,000 (2) | 126,000 (3) |
| John P. DesBarres | 0 (4) | 157,000 (5) | 157,000 (6) |
| James L. Gardner | 52,000 | 90,000 (7) | 142,000 (8) |
| Keith B. Jarrett | 57,438 | 78,750 (9) | 136,188 (10) |
| James R. Montague | 63,500 | 90,000 (11) | 153,500 (12) |
| Marsha R. Perelman | 0 (13) | 123,000 (14) | 123,000 (15) |

(1) Represents the amounts of expense recognized by us in 2006 for financial statement reporting purposes with respect to the common units and deferred common units previously granted to the non-employee directors of our general partner. These amounts were computed in accordance with Financial Accounting Standards (FAS) 123R and were based on the NYSE closing price of our common units on the dates of grant. See Note 13 in the Notes to Consolidated Financial Statements.

(2) As of December 31, 2006, Mr. Cloues had 7,342 deferred common units outstanding.

(3) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 cash annual retainer and (c) $16,000 in meeting fees.

(4) Mr. DesBarres elected to receive all cash fees in deferred common units.

(5) As of December 31, 2006, Mr. DesBarres had 10,755 deferred common units outstanding.

(6) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer, (c) $32,000 in meeting fees and (d) $15,000 annual cash retainer as Chairman of the audit committee of our general partner.

(7) As of December 31, 2006, Mr. Gardner had 3,507 deferred common units outstanding.
(8) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer, (c) $25,000 in meeting fees and (d) $7,000 annual cash retainer as a member of the audit committee of our general partner.
(9) Mr. Jarrett resigned from the board of directors of our general partner in November 2006. As of December 31, 2006, Mr. Jarrett had no deferred common units outstanding.
(10) Consists of (a) $78, 750 annual retainer paid in deferred common units, (b) $17,500 annual cash retainer, (c) $29,000 in meeting fees and (d) $8,750 annual cash retainer as a member of the audit committee of our general partner and $2,188 as Chairman of the compensation and benefits committee of our general partner.
(11) As of December 31, 2006, Mr. Montague had 7,342 deferred common units outstanding.
(12) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer, (c) $31,000 in meeting fees and (d) $10,000 as a member of the audit committee of our general partner and $2,500 as Chairman of the conflicts committee of our general partner.
(13) Ms. Perelman elected to receive all cash fees in common units.
(14) As of December 31, 2006, Ms. Perelman had 6,063 deferred common units outstanding.
(15) Consists of (a) $90,000 annual retainer paid in deferred common units, (b) $20,000 annual cash retainer and (c) $13,000 in meeting fees.

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 NYSE closing price of our common units on the dates on which such awards are granted. Each deferred common unit represents one common unit representing a limited partner interest in us, 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 Chairman 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 Chairmen 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.

**Non-Employee Directors Deferred Compensation Plan**

Our general partner has adopted the Penn Virginia Resource GP, LLC Non-Employee Directors Deferred Compensation Plan. This 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.

**Compensation Committee Interlocks and Insider Participation**

During 2006, Messrs. Cloues, DesBarres, Gardner and Montague and Keith B. Jarrett, who resigned from the board of directors of our general partner in November 2006, 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 of Regulation S-K, "Transactions with Related Persons, Promoters and Certain Control Persons." In 2006, 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.

### Compensation Committee Report

Under the rules established by the SEC, we are required to discuss the compensation and benefits of the executive officers of our general partner, including the CEO, CFO and the other Named Executive Officers. The Compensation and Benefits Committee is furnishing the following report in fulfillment of the SEC's requirements.

The Compensation and Benefits Committee has reviewed the information contained above under the heading "Compensation Discussion and Analysis" and has discussed the Compensation Discussion and Analysis with management. Based upon its review and discussions with management, the Compensation and Benefits Committee recommended to the board of directors of the Partnership's general partner that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

**Compensation and Benefits Committee**

James L. Gardner (Chairman)
Edward B. Cloues, II
John P. DesBarres
James R. Montague

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

### Beneficial Ownership of Units

The following table sets forth, as of February 23, 2007, the amount and percentage of our outstanding common units and Class B units beneficially owned by (i) each person known by us to own beneficially more than 5% of our common units or our Class B 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 Owner | Common Units (1) | Percent of Common Units (2) | Class B Units (1) | Percent of Class B Units (2) | Percent of Total Units |
|---|---|---|---|---|---|
| Penn Virginia GP Holdings, L.P. (3) | 15,541,738 | 37.0% | 4,045,311 | 100% | 42.5% |
| Penn Virginia Resource GP Corp. (3) | 304,621 | * | 0 | * | * |
| Edward B. Cloues, II | 22,233 (4) | * | 0 | * | * |
| A. James Dearlove | 58,224 (5) | * | 0 | * | * |
| John P. DesBarres | 46,379 (6) | * | 0 | * | * |
| James L. Gardner | 4,418 (7) | * | 0 | * | * |
| Keith D. Horton | 53,012 (8) | * | 0 | * | * |
| James R. Montague | 23,311 (9) | * | 0 | * | * |
| Ronald K. Page | 14,246 (10) | * | 0 | * | * |
| Marsha R. Perelman | 15,398 (11) | * | 0 | * | * |
| Frank A. Pici | 27,240 (12) | * | 0 | * | * |
| Nancy M. Snyder | 23,970 (13) | * | 0 | * | * |
| All directors and executive officers as a group (10 persons) | 288,431 (14) | * | 0 | * | * |

* Less than 1%
(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 42,060,974 common units and 4,045,311 Class B units issued and outstanding on February 23, 2007. On February 21, 2007, there were approximately 23,000 holders of our common units and one holder of our Class B units.
(3) Penn Virginia is the ultimate parent company of Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp. As such, Penn Virginia may be deemed to beneficially own the units held by Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp., which together own 37.7% of our common units and 100% of our Class B units. The address for each of Penn Virginia GP Holdings, L.P. and Penn Virginia Resource GP Corp. is c/o Penn Virginia Corporation, Three Radnor Corporate Center, Suite 300, 100 Matsonford Road, Radnor, Pennsylvania 19087.
(4) Includes 8,311 deferred common units.
(5) Includes 15,906 restricted units and 200 common units held by Mr. Dearlove for the benefit of a minor.
(6) Includes 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 12,379 deferred common units.
(7) Reflects 4,418 deferred common units.
(8) Includes 18,044 restricted units and 1,000 common units held by Mr. Horton's spouse.
(9) Includes 2,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan and 8,311 deferred common units.
(10) Includes 14,246 restricted units.
(11) Includes 7,013 deferred common units and 5,000 common units held by a trust of which Ms. Perelman is a trustee and a beneficiary.
(12) Includes 9,522 restricted units.
(13) Includes 8,028 restricted units and 470 common units held by Ms. Snyder for the benefit of a minor child.
(14) Includes 65,746 restricted units, 4,000 common units deferred pursuant to our general partner's non-employee directors deferred compensation plan, 40,432 deferred common units, 5,000 common units held by a trust of which Ms. Perelman is a trustee and a beneficiary, 1,000 common units held by Mr. Horton's spouse and 670 common units held by executive officers for the benefit of minors.

**Equity Compensation Plan Information**

The following table sets forth certain information as of December 31, 2006 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.

| Plan Category | Number of Securities To Be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a) | Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b) | Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c) |
|---|---|---|---|
| Equity compensation plans approved by unitholders | N/A | N/A | N/A |
| Equity compensation plans not approved by unitholders | 0 | N/A | 265,879 |

## Item 13 *Certain Relationships and Related Transactions, and Director Independence*

### Transactions with Related Persons

*Management and Administrative Services*

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 $4.5 million, $2.6 million and $1.5 million for the years ended December 31, 2006, 2005 and 2004.

*Incentive Distributions*

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 $0.275 per common and Class B unit, our general partner will receive incentive distributions equal to (i) 15% of that portion of the distribution per common and Class B unit which exceeds but is not more than $0.325, plus (ii) 25% of that portion of the quarterly distribution per common and Class B unit which exceeds $0.325 but is not more than $0.375, plus (iii) 50% of that portion of the quarterly distribution per common and Class B unit which exceeds $0.375. In 2006, our general partner received total distributions, including incentive distributions, of $28.3 million from us. See also Item 1, "Business—Partnership Distributions."

*Units Purchase Agreement*

In connection with the PVG IPO in December 2006, we entered into a Units Purchase Agreement with PVG. Pursuant to the Units Purchase Agreement, we sold an aggregate of 416,444 common units and 4,045,311 Class B units to PVG in three separate sales in December 2006 and January 2007. The total purchase price paid to us by PVG for the common and Class B units was $113.6 million.

*Omnibus Agreement*

Penn Virginia, us, our general partner and the Operating Company are parties to an Omnibus Agreement that governs potential competition among us. Upon completion of the PVG IPO, PVG became subject to the Omnibus Agreement as an affiliate of Penn Virginia's. The Omnibus Agreement was entered into in connection with our initial public offering in October 2001.

Under the Omnibus Agreement, Penn Virginia and its affiliates, including PVG, are not permitted 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 or they first offers us the opportunity to acquire these 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. In addition, Penn Virginia and its affiliates 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 or its affiliates make any such acquisition, it or they must offer us the opportunity to purchase the coal reserves, timber or related infrastructure following the acquisition and our general partner's conflicts committee will determine whether we should pursue the opportunity. The restriction will terminate upon a change in control of Penn Virginia or our general partner.

*Non-Compete Agreement*

PVG and us are parties to an Non-Compete Agreement that governs potential competition among us. The Non-Compete Agreement was entered into in connection with the PVG IPO in December 2006, but is not effective until PVG is no longer subject to the Omnibus Agreement. Pursuant to the Non-Compete Agreement, PVG will have a right of first refusal with respect to the potential acquisition of any general partner interest, and any other equity interests under common ownership with such general partner, in a publicly traded partnership, other than any partnerships engaged in the coal or timber businesses described above or the business of gathering or processing natural gas or other hydrocarbons. We will have a right of first refusal with respect to the potential acquisition of assets that relate to the business of (i) owning, mining, processing, marketing or transporting coal, (ii) owning, acquiring or leasing coal reserves, (iii) growing, harvesting or selling timber or (iv) the gathering or processing of natural gas or other hydrocarbons.

### Policies Regarding Transactions with Related Persons

Under our Corporate Governance Principles, all directors must recuse themselves from any decision affecting their personal, business or professional interests. In addition, as a general matter, our practice is that any proposed transaction between us (or any of our subsidiaries) and Penn Virginia or PVG (or any of their respective subsidiaries) is approved by the conflicts committee of our general partner. For a discussion of the conflicts committee of our general partner, see "Item 10—Directors, Executive Officers and Corporate Governance—Committees of the Board of Directors of our General Partner—Conflicts Committee." With respect to any proposed transaction with any other related person, as a general matter, our practice is that such transactions are approved by disinterested directors. Our General Counsel advises the Board as to which transactions involve related persons, which transactions require the approval of the conflicts committee of our general partner and which directors are prohibited from voting on a particular transaction. All of the related transactions described above which were entered into since January 1, 2006 were approved in accordance with the foregoing policies.

### Director Independence

Messrs. Cloues, DesBarres, Gardner and Montague and Ms. Perelman are "independent directors," as defined by NYSE Listing Standards and SEC rules and regulations. We refer to those directors as "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 affiliates, Penn Virginia or PVG's general partner.

### 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, or ICFR, for 2006, 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 2006 and 2005, the audit of our ICFR and fees billed for other services rendered by KPMG.

| | 2006 | 2005 |
|---|---|---|
| Audit Fees (1) | $696,100 | $668,300 |
| Audit-Related Fees (2) | 5,000 | 5,000 |
| Tax Fees | 5,300 | — |
| All Other Fees | — | — |
| Total Fees | $706,400 | $673,300 |

(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 2006 and 2005 included $5,000 pertaining to debt compliance letters issued by KPMG for the Notes.

**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 52 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 Registration Statement on 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) Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

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

(3.8) 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 Registration Statement on Form S-1 filed on October 16, 2001).

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

(3.10) Fourth Amended and Restated Limited Liability Company Agreement of Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(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).

(4.3) Second Amendment to Note Purchase Agreement dated as of December 11, 2006 among Penn Virginia Operating Co., LLC, Penn Virginia Resource Partners, L.P. and the noteholders party thereto (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(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) Second Amendment to Amended and Restated Credit Agreement dated as of August 22, 2006 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 Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006).

(10.4) Third Amendment to Amended and Restated Credit Agreement dated as of December 11, 2006 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 December 13, 2006).

(10.5) 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 Registration Statement on Form S-1 filed on October 4, 2001).

(10.6) 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 Registration Statement on Form S-1 filed on October 4, 2001).

(10.7) 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 Registration Statement on Form S-1 filed on October 4, 2001).

(10.8) 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 Registration Statement on Form S-1 filed on October 4, 2001).

(10.9) 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).

(10.10) Non-Compete Agreement dated December 8, 2006 among Penn Virginia GP Holdings, L.P., Penn Virginia Resource Partners, L.P. and Penn Virginia Resource GP, LLC (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 13, 2006).

(10.11) 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).*

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

(10.13) 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).*

(10.14) 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).*

(10.15) 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).*

(10.16) 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.

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* 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 1, 2007

By: /s/ FRANK A. PICI
**(Frank A. Pici, Vice President and Chief Financial Officer)**

March 1, 2007

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<br>**(A. James Dearlove)** | Chairman of the Board and Chief Executive Officer | March 1, 2007 |
| /s/ EDWARD B. CLOUES, II<br>**(Edward B. Cloues, II)** | Director | March 1, 2007 |
| /s/ JOHN P. DESBARRES<br>**(John P. DesBarres)** | Director | March 1, 2007 |
| /s/ JAMES L. GARDNER<br>**(James L. Gardner)** | Director | March 1, 2007 |
| /s/ JAMES R. MONTAGUE<br>**(James R. Montague)** | Director | March 1, 2007 |
| /s/ MARSHA R. PERELMAN<br>**(Marsha R. Perelman)** | Director | March 1, 2007 |
| /s/ FRANK A. PICI<br>**(Frank A. Pici)** | Director and Vice President and Chief Financial Officer | March 1, 2007 |
| /s/ NANCY M. SNYDER<br>**(Nancy M. Snyder)** | Director and Vice President and General Counsel | March 1, 2007 |

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# Partnership Information

## Directors*

**A. James Dearlove**
*Chairman of the Board and Chief Executive Officer; Director, Chief Executive Officer, and President of Penn Virginia Corporation and Chairman of the Board, President and Chief Executive Officer of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.*

**Edward B. Cloues, II**[2]
*Chairman and Chief Executive Officer of K-Tron International, Inc. and Director of Penn Virginia Corporation*

**John P. DesBarres**[1,2,3]
*Former Chairman, President and Chief Executive Officer of Transco Energy Company, Inc.*

**James L. Gardner**[1,2,3]
*Associate Professor, Freed-Hardeman University and Former Executive Vice President and Chief Administrative Officer of Massey Energy Company*

**James R. Montague**[1,2,3]
*Former President of Encana Gulf of Mexico, LLC and former President of IP Petroleum Company and GCO Minerals Company*

**Marsha R. Perelman**
*Founder and Chief Executive Officer of Woodforde Management, Inc. and Director of Penn Virginia Corporation*

**Frank A. Pici**
*Vice President and Chief Financial Officer; Executive Vice President and Chief Financial Officer of Penn Virginia Corporation and Director, Vice President and Chief Financial Officer of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.*

**Nancy M. Snyder**
*Vice President and General Counsel; Executive Vice President, General Counsel and Corporate Secretary of Penn Virginia Corporation and Director, Vice President and General Councel of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.*

## Management*

**A. James Dearlove**
*Chief Executive Officer*

**Keith D. Horton**
*Co-President and Chief Operating Officer—Coal*

**Ronald K. Page**
*Co-President and Chief Operating Officer—Midstream*

**Frank A. Pici**
*Vice President and Chief Financial Officer*

**Nancy M. Snyder**
*Vice President and General Counsel*

**Forrest W. McNair**
*Vice President and Controller*

**Steven A. Hartman**
*Vice President and Treasurer*

**Jean M. Whitehead**
*Secretary*

## Transfer Agent and Registrar

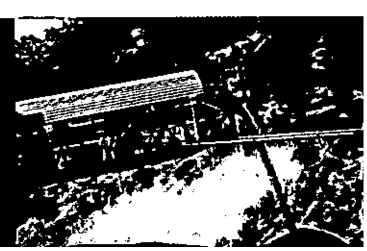
**American Stock Transfer and Trust Company**
Mailing Address:
59 Maiden Lane
New York, NY 10038
(800) 937-5449 phone
(718) 236-2641 fax

## Certifications

In 2006, PVR submitted our Section 303A.12(a) chief executive officer certification to the New York Stock Exchange. We have also filed with the Securities and Exchange Commission, as an exhibit to our most recently filed Annual Report on Form 10-K, the Sarbanes-Oxlely Act Section 302 certifications.



* Of our general partner, PVG GP, LLC
(1) Member of the Audit Committee
(2) Member of the Compensation and Benefits Committee
(3) Member of the Conflicts Committee



**Penn Virginia**
**Resource Partners, L.P.**

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