UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2006

or

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

For the transition period from ______________ to ______________

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 No.)

THREE RADNOR CORPORATE CENTER, SUITE 300
100 MATSONFORD ROAD
RADNOR, PA 19087
(Address of principal executive offices) (Zip Code)

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

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by a 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 [X] 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 [X] No

As of May 1, 2006, 33,994,650 common and 7,649,880 subordinated limited partner units were outstanding.

PENN VIRGINIA RESOURCE PARTNERS, L.P.

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PART I. FINANCIAL INFORMATION

Item 1 ***Financial Statements***

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME – unaudited
(in thousands, except per unit data)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Revenues		
Natural gas midstream	$ 109,181	$ 26,278
Coal royalties	22,422	18,053
Coal services	1,426	1,270
Other	2,135	589
Total revenues	135,164	46,190
Expenses		
Cost of midstream gas purchased	98,651	21,837
Operating	3,478	1,827
Taxes other than income	698	382
General and administrative	5,270	2,765
Depreciation, depletion and amortization	8,821	5,079
Total expenses	116,918	31,890
Operating income	18,246	14,300
Other income (expense)		
Interest expense	(4,067)	(3,114)
Interest income	294	279
Derivative losses	(6,133)	(13,936)
Net income (loss)	$ 8,340	$ (2,471)
General partner's interest in net income (loss)	$ 510	$ (58)
Limited partners’ interest in net income (loss)	$ 7,830	$ (2,413)
Basic and diluted net income (loss) per limited partner unit, common and subordinated	$ 0.19	$ (0.07)
Weighted average number of units outstanding, basic and diluted:		
Common	33,994	25,236
Subordinated	7,650	11,474

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(in thousands)

Assets	**March 31, 2006**	**December 31, 2005**
Current assets	(unaudited)	
Cash and cash equivalents	$ 9,121	$ 23,193
Accounts receivable	67,894	76,398
Derivative assets	3,783	10,235
Other current assets	2,946	2,724
Total current assets	83,744	112,550
Property, plant and equipment	542,533	535,040
Accumulated depreciation, depletion and amortization	(83,783)	(76,258)
Net property, plant and equipment	458,750	458,782
Equity investments	27,002	26,672
Goodwill	7,718	7,718
Intangibles, net	36,785	38,051
Derivative assets	6,690	8,536
Other long-term assets	5,536	5,570
Total assets	$ 626,225	$ 657,879
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable and accrued liabilities	$ 52,358	$ 68,004
Current portion of long-term debt	9,814	8,108
Deferred income	6,732	5,073
Derivative liabilities	16,515	20,700
Total current liabilities	85,419	101,885
Deferred income	8,324	10,194
Other liabilities	3,736	3,749
Derivative liabilities	11,889	11,246
Long-term debt	241,888	246,846
Commitments and contingencies		
Partners' capital	274,969	283,959
Total liabilities and partners' capital	$ 626,225	$ 657,879

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS - Unaudited
(in thousands)

	Three Months Ended March 31,	
	2006	**2005**
Cash flows from operating activities		
Net income (loss)	$ 8,340	$ (2,471)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	8,821	5,079
Derivative losses	6,133	13,936
Non-cash interest expense	191	1,225
Equity earnings	(330)	(298)
Changes in operating assets and liabilities	(9,838)	(6,026)
Net cash provided by operating activities	13,317	11,445
Cash flows from investing activities		
Acquisitions, net of cash acquired	(3,069)	(204,984)
Additions to property, plant and equipment	(5,496)	(289)
Other	-	52
Net cash used in investing activities	(8,565)	(205,221)
Cash flows from financing activities		
Distributions to partners	(15,524)	(10,411)
Proceeds from borrowings	-	211,800
Repayments of borrowings	(3,300)	(131,500)
Proceeds from issuance of partners' capital	-	127,730
Payments for debt issuance costs	-	(2,039)
Net cash provided by (used in) financing activities	(18,824)	195,580
Net increase in cash and cash equivalents	(14,072)	1,804
Cash and cash equivalents – beginning of period	23,193	20,997
Cash and cash equivalents – end of period	$ 9,121	$ 22,801
Supplemental disclosure:		
Cash paid for interest	$ 5,352	$ 3,105

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Unaudited
March 31, 2006

1. Organization

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

In our coal segment, we do not operate any mines. Instead, we enter into leases with various third-party operators which give those operators the right to mine coal reserves on our land in exchange for royalty payments. We also provide fee-based infrastructure facilities to some of our lessees and third parties to generate coal services revenues. These facilities include coal loading facilities, preparation plants and coal handling facilities located at end-user industrial plants. We also sell timber growing on our land.

We purchased our natural gas midstream business on March 3, 2005, through the acquisition of Cantera Gas Resources, LLC (the "Cantera Acquisition"). As a result of the Cantera 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.

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

2. Summary of Significant Accounting Policies

Our accounting policies are consistent with those described in our Annual Report on Form 10-K for the year ended December 31, 2005, except as discussed below. Please refer to such Form 10-K for a further discussion of those policies.

Basis of Presentation

The accompanying unaudited consolidated financial statements include the accounts of the Partnership and all wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and Securities and Exchange Commission regulations. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation of the consolidated financial statements have been included. These financial statements should be read in conjunction with our consolidated financial statements and footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2005. Operating results for the three months ended March 31, 2006, are not necessarily indicative of the results that may be expected for the year ending December 31, 2006. Certain reclassifications have been made to conform to the current period's presentation.

3. Derivative Instruments and Hedging Activities

Natural Gas Midstream Segment Commodity Derivatives

The fair values of our derivative agreements are determined based on forward price quotes and regression analysis for the respective commodities as of March 31, 2006. The following table sets forth our positions as of March 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)
Ethane Swaps	**(in gallons)**	**(per gallon)**	
Second Quarter 2006 through Fourth Quarter 2006	68,880	$ 0.4770	$ (2,359)
First Quarter 2007 through Fourth Quarter 2007	34,440	$ 0.5050	(1,343)
First Quarter 2008 through Fourth Quarter 2008	34,440	$ 0.4700	(1,396)
Propane Swaps	**(in gallons)**	**(per gallon)**	
Second Quarter 2006 through Fourth Quarter 2006	52,080	$ 0.7060	(4,139)
First Quarter 2007 through Fourth Quarter 2007	26,040	$ 0.7550	(1,992)
First Quarter 2008 through Fourth Quarter 2008	26,040	$ 0.7175	(2,075)
Crude Oil Swaps	**(in barrels)**	**(per barrel)**	
Second Quarter 2006 through Fourth Quarter 2006	1,100	$ 44.45	(7,895)
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(3,599)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(3,293)
Natural Gas Swaps	**(in MMbtu)**	**(per MMbtu)**	
Second Quarter 2006 through Fourth Quarter 2006	7,500	$ 7.05	1,994
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	3,608
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	2,821
			$ (19,668)

Based upon the assessment of derivative agreements at March 31, 2006, we reported (i) a net derivative liability related to the natural gas midstream segment of $19.7 million, (ii) a loss in accumulated other comprehensive income of $8.7 million and (iii) a net unrealized loss on derivatives for hedge ineffectiveness of $0.1 million for the three months ended March 31, 2006, related to cash flow hedges in the natural gas midstream segment. In connection with monthly settlements, we recognized net hedging losses in natural gas midstream revenues of $2.2 million for the three months ended March 31, 2006, and net hedging gains in cost of midstream gas purchased of $2.4 million for the three months ended March 31, 2006. Based upon future commodity prices as of March 31, 2006, we expect to realize $12.9 million of hedging losses within the next 12 months. The amounts that we will ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. Because all hedged volumes relate to periods beginning after March 31, 2005, we had no monthly settlements and recognized no net hedging losses in natural gas midstream revenues for the three months ended March 31, 2005.

At the time we entered into our natural gas derivatives and certain natural gas liquid ("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 and recognized a net mark-to-market loss of $6.0 million in the first quarter of 2006.

In November 2005, we entered into a basis swap for the period January 2006 through July 2006. The basis swap relates to purchases of natural gas in the Texas/Oklahoma Basin region. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*, changes in market value of the derivative instrument are charged to earnings. At March 31, 2006, we reported (i) a derivative liability of approximately $0.3 million and (ii) a derivative loss of $0.1 million for the three months ended March 31, 2006, related to the basis swap.

Discontinuation of Hedge Accounting

Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we will recognize 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, included in accumulated other comprehensive income will be reported in future earnings through 2008 as the original hedged transactions occur. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by mark-to-market gains and losses which fluctuate with volatile oil and gas prices.

Interest Rate Swaps

In September 2005, we entered into interest rate swap agreements to establish fixed rates on $60 million of the LIBOR-based portion of the outstanding balance on our revolving credit facility until March 2010 (the "Revolver Swaps"). We pay a weighted average fixed rate of 4.22 percent on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver 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 $2.0 million at March 31, 2006, and (ii) a gain in accumulated other comprehensive income of $1.3 million for the three months ended March 31, 2006, related to the Revolver Swaps. In connection with periodic settlements, we recognized $0.1 million in net hedging gains in interest expense for the three months ended March 31, 2006. Based upon future interest rate curves at March 31, 2006, we expect to realize $0.5 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.

4. Partners' Capital and Distributions

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, respectively, 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.

Net Income per Limited Partner Unit

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

Cash Distributions

We make quarterly cash distributions of our available cash, generally defined as all of our cash and cash equivalents on hand at the end of each quarter less cash reserves established by our general partner at its sole discretion. According to our partnership agreement, the 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 the three months ended March 31, 2006 and 2005 (in thousands, except per unit information):

	Three Months Ended March 31,	
	2006	2005
Limited partner units	$ 14,576	$ 10,168
General partner interest (2%)	297	203
Incentive distribution rights	651	40
Total cash distributions paid	$ 15,524	$ 10,411
Total cash distributions paid per unit	$ 0.3500	$ 0.2813

We paid a quarterly distribution of $0.35 per unit in February 2006. In April 2006, we announced a $0.35 per unit distribution for the three months ended March 31, 2006, or $1.40 per unit on an annualized basis. The distribution will be paid on May 15, 2006, to unitholders of record at the close of business on May 5, 2006.

5. Related Party Transactions

General and Administrative

Penn Virginia charges us for certain corporate administrative expenses which are allocable to its subsidiaries. When allocating general corporate expenses, consideration is given to property and equipment, payroll and general corporate overhead. Any direct costs are paid by us. Total corporate administrative expenses charged to us totaled $1.6 million and $0.4 million for the three months ended March 31, 2006 and 2005. 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 $3.5 million as of March 31, 2006. 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.

6. 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. Accumulated other comprehensive income was $(6.7) million at March 31, 2006. For the three months ended March 31, 2006 and 2005, the components of comprehensive income were as follows (in thousands):

	Three Months Ended March 31, 2006	2005
Net income (loss)	$ 8,340	$ (2,471)
Unrealized holding losses on hedging activities	(1,966)	(2,726)
Reclassification adjustment for hedging activities	160	-
Comprehensive income (loss)	$ 6,534	$ (5,197)

7. Commitments and Contingencies

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 March 31, 2006, environmental liabilities included $2.4 million, which represents our best estimate of our liabilities as of that date 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 a 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.

8. Segment Information

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

Coal

The coal segment includes:

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

Natural Gas Midstream

The natural gas midstream segment derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services.

Segment Financial Information

The following table presents a summary of certain financial information relating to our segments (in thousands):

	Coal	(1) Natural Gas Midstream	Consolidated
For the Three Months Ended March 31, 2006:			
Revenues	$ 25,328	$ 109,836	$ 135,164
Cost of midstream gas purchased	-	98,651	98,651
Operating costs and expenses	3,509	5,937	9,446
Depreciation, depletion and amortization	4,752	4,069	8,821
Operating income	$ 17,067	$ 1,179	$ 18,246
Interest expense, net			(3,773)
Derivative losses			(6,133)
Net income			$ 8,340
Additions to property and equipment	$ 6,004	$ 2,561	$ 8,565
For the Three Months Ended March 31, 2005:			
Revenues	$ 19,812	$ 26,378	$ 46,190
Cost of midstream gas purchased	-	21,837	21,837
Operating costs and expenses	3,663	1,311	4,974
Depreciation, depletion and amortization	3,855	1,224	5,079
Operating income	$ 12,294	$ 2,006	$ 14,300
Interest expense, net			(2,835)
Derivative losses			(13,936)
Net loss			$ (2,471)
Additions to property and equipment	$ 38	$ 251	$ 289

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

Item 2 ***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. (the "Partnership," "we," "us" or "our") should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 1, "Financial Statements." Our discussion and analysis include the following items:

- Overview of Business
- Acquisitions and Investments
- Overview of Current Performance
- Critical Accounting Policies and Estimates
- Liquidity and Capital Resources
- Results of Operations
- Environmental
- Recent Accounting Pronouncements
- Forward-Looking Statements

Overview of Business

We are a Delaware limited partnership formed by Penn Virginia Corporation ("Penn Virginia") in 2001 primarily to engage in the business of managing coal properties in the United States. Penn Virginia contributed its coal properties and related assets to us and, effective with the closing of our initial public offering in October 2001, our common units began trading publicly on the New York Stock Exchange under the symbol "PVR."

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

We continually evaluate acquisition opportunities that are accretive to cash available for distribution to our unitholders. These opportunities include, but are not limited to, acquiring additional coal properties and reserves, acquiring or constructing assets for coal services and natural gas midstream gathering and processing, all of which would provide a primarily fee-based revenue stream.

Acquisitions and Investments

We expect to complete construction and commence operation of a new 600-ton per hour coal processing plant and rail loading facility in the third quarter of 2006 for one of our lessees located in Knott County in eastern Kentucky. Since acquiring fee ownership and lease rights to the property's coal reserves in July 2005, we made cumulative capital expenditures of $4.0 million related to the construction of the facility as of March 31, 2006. Total capital expenditures for the construction are expected to be approximately $14 to $15 million.

Overview of Current Performance

Operating income for the first quarter of 2006 was $18.2 million. The coal segment contributed $17.1 million, or 94 percent, to operating income, and the natural gas midstream segment contributed $1.1 million, or six percent. A description of each of our reportable segments follows:

- Coal – the leasing of mineral interests and subsequent collection of royalties, the providing of fee-based coal handling, transportation and processing infrastructure facilities and the development and harvesting of timber.
- Natural Gas Midstream – gas processing, gathering and other related services.

Coal Segment

In the first quarter of 2006, coal royalty revenues increased 24 percent, or $4.4 million, over the same period last year due to more coal being mined by our lessees and increasing coal prices. Tons produced by our lessees increased from 6.7 million tons in the first quarter of 2005 to 7.7 million tons in the first quarter of 2006, and our average gross royalties per ton increased from $2.69 in the first quarter of 2005 to $2.90 in the first quarter of 2006. The Illinois Basin coal reserves we acquired in July 2005 enhanced our coal royalty revenues in the first quarter of 2006 by $1.4 million. Generally, as coal prices increase, our average royalties per ton also increase because most of our lessees pay royalties based on the gross sales prices of the coal mined.

In managing our properties, we actively work with our lessees to develop efficient methods to exploit our reserves and to maximize production from our properties. We earn revenues from providing fee-based coal preparation and transportation services to our lessees, which enhance their production levels and generate additional coal royalty revenues, and from industrial third party coal end-users by owning and operating coal handling facilities through our joint venture with Massey Energy Company ("Massey"). Coal services revenues increased to $1.4 million in the first quarter of 2006 from $1.3 million in the first quarter of 2005. We believe that these types of fee-based infrastructure assets provide good investment and cash flow opportunities for us, and we continue to look for additional investments of this type as well as other primarily fee-based assets. We also earn revenues from oil and gas royalty interests, coal transportation ("wheelage") rights and the sale of standing timber on our properties.

As of March 31, 2006, our primary coal reserves and coal infrastructure assets were located on the following properties:

- in central Appalachia, at properties 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;
- in northern Appalachia, at properties in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;
- in the Illinois Basin, at properties in Henderson and Webster Counties, Kentucky; and
- in the San Juan Basin, at properties in McKinley County, New Mexico.

Natural Gas Midstream Segment

Increasing NGL prices helped drive the gross processing margin for our natural gas midstream operations from $1.14 per thousand cubic feet ("Mcf") in the first quarter of 2005 to $1.25 per Mcf in the first quarter of 2006, excluding a $4.6 million non-cash reserve charge in the first quarter of 2006. We charged $4.6 million to cost of midstream gas purchased to reserve for amounts related to balances assumed as part of the acquisition of Cantera Gas Resources, LLC (the "Cantera Acquisition") for which we are still evaluating the possibility of collection. Inlet volumes at our gas processing plants and gathering systems were 134 million cubic feet ("MMcf") per day for the first quarter of 2006, an increase over 126 MMcf per day in the first quarter of 2005.

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

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 midstream gas purchased and accounts payable are made based on estimates of natural gas purchased and NGLs and natural gas sold, and our financial results include estimates of production and revenues for the period of actual production. Any differences, which we do not expect to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized. Approximately 57 percent of natural gas midstream revenues for the three months ended March 31, 2006, related to three customers.

Coal Royalty Revenues

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

Derivative Instruments and Hedging Activities

We historically have entered into derivative financial instruments that were expected to 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 in our statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until realized. The position reflected in the statement of income is based on the actual settlements with the counterparty. We include this gain or loss in natural gas midstream revenues or cost of midstream gas purchased, depending on the commodity. Effective January 1, 2006, some of our derivatives did not qualify for hedge accounting under SFAS No. 133, and changes in market value of these derivative instruments were recognized in earnings. When we do not use hedge accounting, we could experience significant changes in the estimate of non-cash derivative gain or loss recognized in revenue 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.

Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we will recognize 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, included in accumulated other comprehensive income will be reported in future earnings through 2008 as the original hedged transactions occur. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by mark-to-market gains and losses which fluctuate with volatile 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 reserves have been estimated by our own geologists and outside consultants. Our estimates of coal reserves are updated annually and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. We estimate timber inventory using statistical information and data obtained from physical measurements, site maps, photo-types and other information gathering techniques. These estimates are updated annually and may result in adjustments of timber volumes and depletion rates, which are recognized prospectively.

Liquidity and Capital Resources

Since closing our initial public offering in October 2001, cash generated from operations and our borrowing capacity, supplemented by proceeds from the issuance of new common units, have been sufficient to meet our scheduled distributions, working capital requirements and capital expenditures. Our primary cash requirements consist of quarterly distributions to our general partner and unitholders, normal operating expenses, interest and principal payments on our long-term debt and acquisitions of new assets or businesses. Summarized cash flow statements for the three months ended March 31, 2006 and 2005, consolidating our segments are set forth below (in millions).

For the three months ended March 31, 2006	Coal	Natural Gas Midstream	Consolidated
Cash flows from operating activities:			
Net income (loss) contribution	$ 13.1	$ (4.7)	$ 8.4
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	4.6	10.2	14.8
Net change in operating assets and liabilities	(0.7)	(9.2)	(9.9)
Net cash provided by (used in) operating activities	$ 17.0	$ (3.7)	13.3
Cash flows from investing activities:			
Additions to property and equipment	$ (3.1)	$ —	(3.1)
Acquisitions	(3.1)	—	(3.1)
Other	—	(2.4)	(2.4)
Net cash used in investing activities	$ (6.2)	$ (2.4)	(8.6)
Cash flows from financing activities:			
PVR distributions paid			(15.5)
PVR debt repayments			(3.3)
Other			—
Net cash used in financing activities			(18.8)
Net decrease in cash and cash equivalents			(14.1)
Cash and cash equivalents—beginning of period			23.2
Cash and cash equivalents—end of period			$ 9.1

For the three months ended March 31, 2005	Coal	Natural Gas Midstream	Consolidated
Cash flows from operating activities:			
Net income (loss) contribution	$ 9.5	$ (12.0)	$ (2.5)
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	4.8	15.1	19.9
Net change in operating assets and liabilities	(2.5)	(3.5)	(6.0)
Net cash provided by (used in) operating activities	$ 11.8	$ (0.4)	11.4
Cash flows from investing activities:			
Additions to property and equipment	$ (0.1)	$ (0.2)	(0.3)
Acquisitions, net of cash acquired	(9.3)	(195.7)	(205.0)
Other	—	0.1	0.1
Net cash used in investing activities	$ (9.4)	$ (195.8)	(205.2)
Cash flows from financing activities:			
PVR distributions paid			(10.4)
PVR debt proceeds, net of repayments			80.3
Proceeds received from the issuance of partners' capital			127.7
Other			(2.0)
Net cash provided by financing activities			195.6
Net increase (decrease) in cash and cash equivalents			1.8
Cash and cash equivalents—beginning of period			21.0
Cash and cash equivalents—end of period			$ 22.8

Cash Flows

The overall increase in cash provided by operations for the three months ended March 31, 2006 compared to the same period of 2005 was primarily attributable to higher average gross coal royalties per ton and accretive cash flows from our natural gas midstream business, which was acquired in March 2005.

We made cash investments during the three months ended March 31, 2006, primarily for coal reserve acquisitions, coal loadout facility construction and natural gas midstream gathering systems. Other investments in the same period of 2005 included the acquisition of our natural gas midstream business, net of cash acquired, and coal reserve acquisitions.

Capital expenditures, including non-cash items, for the three months ended March 31, 2006 and 2005, were as follows:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	(in millions)	
Coal		
Acquisitions	$ 2.7	$ 9.3
Maintenance expenditures	0.1	0.1
Other property and equipment expenditures	2.1	-
Total	4.9	9.4
Natural gas midstream		
Acquisitions, net of cash acquired	-	195.7
Maintenance expenditures	0.6	0.2
Other property and equipment expenditures	2.0	-
Total	2.6	195.9
Total capital expenditures	$ 7.5	$ 205.3

Cash flows from operations funded our capital expenditures for the three months ended March 31, 2006. To finance our acquisitions in the three months ended March 31, 2005, we borrowed $80.3 million, net of repayments, received proceeds of $125.2 million from our secondary public offering and received a $2.5 million contribution from our general partner. Distributions to partners increased to $15.5 million in the three months ended March 31, 2006, from $10.4 million in the three months ended March 31, 2005, because we increased the quarterly unit distribution.

Long-Term Debt

As of March 31, 2006, we had outstanding borrowings of $251.7 million, consisting of $172.0 million borrowed under our revolving credit facility and $79.7 million of senior unsecured notes (the "Notes"). The current portion of the Notes as of March 31, 2006, was $9.8 million.

Revolving Credit Facility. As of March 31, 2006, we had $172.0 million outstanding under our $300 million revolving credit facility (the "Revolver") that matures in March 2010. 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 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 Revolver's interest rate fluctuates based on our ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 1.00 percent if we select the base rate borrowing option under the credit agreement or at a rate derived from the London Interbank Offering Rate ("LIBOR") plus an applicable margin ranging from 1.00 percent to 2.00 percent if we select the LIBOR-based borrowing option.

The 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 additional borrowing capacity under the Revolver to approximately $145.9 million as of March 31, 2006. The Revolver prohibits us from making certain distributions, including distributions to unitholders if any potential default or event of default occurs or would result from such unitholder 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 March 31, 2006, we were in compliance with all of our covenants under the Revolver.

Senior Unsecured Notes. As of March 31, 2006, we owed $79.7 million under the Notes. The Notes bear interest at a fixed rate of 6.02 percent and mature over a ten-year period ending in March 2013, with semi-annual principal and interest payments. The Notes contain various covenants similar to those contained in the Revolver. The Notes are equal in right of payment with all other unsecured indebtedness, including the Revolver. As of March 31, 2006, we were in compliance with all of our covenants under the Notes. The Notes require us to obtain an annual confirmation of our credit rating, with a 1.00 percent increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. In March 2006, our investment grade credit rating was confirmed by Dominion Bond Rating Services.

Interest Rate Swaps. In September 2005, we entered into two interest rate swap agreements with notional amounts totaling $60 million to establish a fixed rate on the LIBOR-based portion of the outstanding balance of the Revolver until March 2010 (the "Revolver Swaps"). We pay a fixed rate of 4.22 percent on the notional amount, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver 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 1.25 percent in effect as of March 31, 2006, the total interest rate on the $60 million portion of Revolver borrowings covered by the Revolver Swaps was 5.47 percent at March 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 2006, we anticipate making capital expenditures, excluding acquisitions, of $16 to $18 million for coal services related projects and other property and equipment and $8 to $10 million for natural gas midstream system expansion projects. Management believes that cash flow provided by operating activities will be sufficient to fund these capital expenditures. Additional funding will be provided as needed from the Revolver, under which we had $145.9 million of borrowing capacity as of March 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.

Results of Operations

Selected Financial Data – Consolidated

	Three Months Ended March 31,	
	2006	**2005**
	(in millions, except per unit data)	
Revenues	$ 135.2	$ 46.2
Expenses	$ 116.9	$ 31.9
Operating income	$ 18.2	$ 14.3
Net income (loss)	$ 8.3	$ (2.5)
Net income (loss) per limited partner unit, basic and diluted	$ 0.19	$ (0.13)
Cash flows provided by operating activities	$ 13.3	$ 11.4

The increase in net income for the three months ended March 31, 2006, compared to the same period in 2005 was primarily attributable to a $3.9 million increase in operating income and a $7.8 million decrease in non-cash derivative losses, partially offset by a $1.0 million increase in interest expense for borrowings used to fund 2005 acquisitions. Operating income increased in the three months ended March 31, 2006, primarily due to the contribution of the natural gas midstream segment that was acquired in March 2005 and increased coal royalty revenue resulting from higher coal prices.

Coal Segment

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

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

Operations and Financial Summary – Coal Segment

Three Months Ended March 31, 2006, Compared with Three Months Ended March 31, 2005

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005	% Change
Financial Highlights	(in millions, except as noted)		
Revenues			
Coal royalties	$ 22.4	$ 18.1	24%
Coal services	1.4	1.3	8%
Other	1.5	0.4	275%
Total revenues	25.3	19.8	28%
Expenses			
Operating	1.0	1.0	-
Taxes other than income	0.3	0.3	-
General and administrative	2.2	2.4	(8%)
Operating expenses before non-cash charges	3.5	3.7	(5%)
Depreciation, depletion and amortization	4.7	3.8	24%
Total expenses	8.2	7.5	9%
Operating income	$ 17.1	$ 12.3	39%
Operating Statistics			
Royalty coal tons produced by lessees (tons in millions)	7.7	6.7	15%
Average royalty per ton ($/ton)	$ 2.90	$ 2.69	8%

Revenues. Coal royalty revenues increased due to a higher average royalty per ton and increased production. The average royalty per ton increased to $2.90 in the first quarter of 2006 from $2.69 in the first quarter of 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 stronger market conditions for coal resulting in higher prices. Coal production by our lessees increased primarily due to new production on our Illinois Basin property, which we acquired in the third quarter of 2005.

Other revenues increased primarily due to the following factors. In the three months ended March 31, 2006, we received approximately $0.4 million in revenues for the management of certain coal properties, approximately $0.2 million of rental income from railcars purchased in the second quarter of 2005 and approximately $0.1 million of royalty income from oil and natural gas royalty interests acquired in March 2005. We also received approximately $0.2 million of additional wheelage fees in the three months ended March 31, 2006, primarily as a result of an April 2005 acquisition.

Expenses. Operating expenses did not increase despite the increase in production because production on our subleased properties decreased by 29 percent to 0.8 million tons in the first quarter of 2006 due to the movement of longwall mining operations at one of these properties. Depreciation, depletion and amortization expense increased due to the increase in production and a higher depletion rate on reserves acquired in 2005.

Natural Gas Midstream Segment

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

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

Operations and Financial Summary – Natural Gas Midstream Segment

Three Months Ended March 31, 2006, Compared with Three Months Ended March 31, 2005

	Three Months Ended March 31,		Three Months Ended March 31,	
	2006	2005 (1)	2006	2005 (1)
	(in millions, except as noted)		(per Mcf)	
Financial Highlights				
Revenues				
Residue gas	$ 78.5	$ 17.0		
Natural gas liquids	28.0	8.3		
Condensate	2.3	-		
Gathering and transportation fees	0.4	1.0		
Total natural gas midstream revenues	109.2	26.3		
Marketing revenue, net	0.6	0.1		
Total revenues	109.8	26.4	$ 9.11	$ 6.75
Expenses				
Cost of midstream gas purchased	98.7	21.9	8.18	5.59
Operating	2.5	0.8	0.21	0.20
Taxes other than income	0.4	0.1	0.03	0.03
General and administrative	3.0	0.4	0.25	0.11
Depreciation and amortization	4.1	1.2	0.34	0.31
Total operating expenses	108.7	24.4	9.01	6.24
Operating income	$ 1.1	$ 2.0	$ 0.10	$ 0.51
Operating Statistics				
Inlet volumes (billion cubic feet)	12.1	3.9		
Midstream processing margin (2)	$ 10.5	$ 4.4	$ 0.87	$ 1.14

(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 midstream gas purchased. Excluding the effect of a $4.6 million non-cash reserve charge, the midstream processing margin per Mcf for the three months ended March 31, 2006, would have been $1.25 per Mcf.

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 average realized sales price from $6.75 per Mcf in the first quarter of 2005 to $9.11 per Mcf in the first quarter of 2006 is consistent with overall market increases in NGL and natural gas prices.

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

Cost of midstream gas purchased consisted of amounts payable to third-party producers for gas purchased under percentage of proceeds and keep-whole contracts. The increase in the average purchase price for gas from $5.59 in the first quarter of 2005 to $8.18 in the first quarter of 2006 is primarily due to overall market increases in natural gas prices. Included in cost of midstream gas purchased for the three months ended March 31, 2006, was a $4.6 million non-cash charge to reserve for amounts related to balances assumed as part of the Cantera Acquisition for which we are still evaluating the possibility of collection. Excluding this non-cash charge, the midstream processing margin per Mcf would have been $1.25 per Mcf, an increase of seven percent from $1.13 in the first quarter of 2005.

General and administrative expenses per Mcf increased from $0.11 in the first quarter of 2005 to $0.25 in the first quarter of 2006, primarily due to additional personnel added to support the business and increased reimbursement to our general partner for corporate overhead costs.

Other

Interest Expense. Interest expense for the three months ended March 31, 2006, was higher than interest expense in the same period in 2005 primarily due to interest incurred on additional borrowings under the Revolver to finance the Cantera Acquisition and coal property acquisitions in 2005.

Derivative Losses. Non-cash derivative losses of $6.1 million for the three months ended March 31, 2006, primarily resulted from mark-to-market adjustments on certain derivatives that no longer qualified for hedge accounting. The $13.9 million in derivative losses for the three months ended March 31, 2005, represented the change in the market value of derivative agreements between the time we entered into the agreements in January 2005 and the time they qualified for hedge accounting after closing the Cantera Acquisition in March 2005.

For the three months ended March 31, 2006, in addition to the $6.1 million derivative losses discussed above, we recognized a net derivative gain of $0.3 million which is reflected primarily in natural gas midstream revenues and cost of midstream gas purchased. We made net cash disbursements of $2.9 million on derivative settlements during the three months ended March 31, 2006.

Environmental

The operations of our coal lessees and our natural gas midstream segment are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of our coal property leases impose liability for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of our coal lessees and our natural gas midstream segment comply with existing regulations and does not expect any material impact on our financial condition or results of operations.

As of March 31, 2006 and 2005, our environmental liabilities included $2.4 million and $1.5 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Recent Accounting Pronouncements

No accounting pronouncements issued in the first quarter of 2006 are expected to have a material effect on our consolidated financial position, results of operations or cash flows.

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 (the "Exchange Act"). 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 following:

- our ability to generate sufficient cash from our midstream and coal businesses to pay the minimum quarterly distribution to our general partner and our unitholders;
- energy prices generally and specifically, the respective prices of natural gas, NGLs and coal;
- the relationship between natural gas and NGL prices;
- the relationship between the price of coal and the prices of natural gas and oil;
- the volatility of commodity prices for coal, natural gas and NGLs;
- the projected supply of and demand for coal, natural gas and NGLs;
- the ability to successfully integrate and manage our new midstream business;
- the ability to acquire new coal reserves on satisfactory terms;
- the price for which new coal reserves can be acquired;
- the ability to lease new and existing coal reserves;
- the ability to continually find and contract for new sources of natural gas supply;
- the ability to retain our existing or acquire new midstream customers;
- the ability of our coal lessees to produce sufficient quantities of coal on an economic basis from our reserves;
- the ability of our coal lessees to obtain favorable contracts for coal produced from our reserves;
- competition among producers in the coal industry generally and among midstream companies;
- exposure to the credit risk of our coal lessees and our midstream customers;
- the experience and financial condition of our coal lessees, including their ability to satisfy their royalty, environmental, reclamation and other obligations to us and others;
- the ability to expand our midstream business by constructing new gathering systems, pipelines and processing facilities on an economic basis and in a timely manner;
- the extent to which the amount and quality of actual coal production differs from estimated recoverable proved coal reserves;

- unanticipated geological problems;
- the dependence of our midstream business on having connections to third party pipelines;
- availability of required materials and equipment;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- the failure of our coal infrastructure or our coal lessees' mining equipment or processes to operate in accordance with specifications or expectations;
- delays in anticipated start-up dates of our coal lessees' mining operations and related coal infrastructure projects;
- environmental risks affecting the mining of coal reserves and the production, gathering and processing of natural gas;
- the timing of receipt of necessary governmental permits by our coal lessees;
- the risks associated with having or not having price risk management programs;
- labor relations and costs;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters;
- uncertainties relating to the outcome of litigation regarding permitting of the disposal of coal overburden;
- risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions (including the impact of potential terrorist attacks);
- coal handling joint venture operations;
- changes in financial market conditions; and
- other risks set forth in Item 1A, "Risk Factors," of our Annual Report on Form 10-K for the year ended December 31, 2005.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission, including our Annual Report on Form 10-K for the year ended December 31, 2005. 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 3 ***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 meet their payment obligations to us.

Interest Rate Risk

As of March 31, 2006, our $172.0 million of outstanding indebtedness under the Revolver carried a variable interest rate throughout its term. We executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a fixed rate of 4.22 percent plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133.

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. These financial instruments were historically designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 139. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets is significantly affected by energy price fluctuations. During the first quarter of 2006, we reported a $6.1 million derivative loss for mark-to-market adjustments on certain derivatives that no longer qualified for hedge accounting effective January 1, 2006.

Because our natural gas derivatives and a large portion of our NGL derivatives no longer qualify for hedge accounting and to increase clarity in our financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we will recognize 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, included in accumulated other comprehensive income will be reported in future earnings through 2008 as the original hedged transactions occur. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by mark-to-market gains and losses which fluctuate with volatile oil and gas prices.

See the discussion and tables in Note 3 in the Notes to Consolidated Financial Statements for a description of our derivative program and a listing of open derivative agreements and their fair value as of March 31, 2006.

Item 4 ***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 March 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 March 31, 2006, such disclosure controls and procedures were effective.

(b) Changes in Internal Control over Financial Reporting

No changes were made in our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except that we evaluated the controls in our natural gas midstream business that we acquired in March 2005 and have integrated those controls into our existing internal control structure.

PART II. OTHER INFORMATION

Items 1, 2, 3, 4 and 5 are not applicable and have been omitted.

Item 6 ***Exhibits***

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, 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

Date:	May 9, 2006	By:	/s/ Frank A. Pici Frank A. Pici Vice President and Chief Financial Officer
Date:	May 9, 2006	By:	/s/ Forrest W. McNair Forrest W. McNair Vice President and Controller