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 June 30, 2005

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)

Virginia	23-3087517
(State or Other Jurisdiction of Incorporation of Organization)	(I.R.S. Employer Identification No.)

THREE RADNOR CORPORATE CENTER, SUITE 230
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.

Yes ___X___ No ________

Indicate by a check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes ___X___ No ________

As of August 1, 2005, 15,084,755 common and 5,737,410 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 June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Revenues				
Natural gas midstream	$ 86,995	$ -	$ 113,273	$ -
Coal royalties	20,129	17,517	38,182	34,377
Other	4,230	1,215	6,089	2,318
Total revenues	111,354	18,732	157,544	36,695
Expenses				
Cost of gas purchased	74,374	-	96,211	-
Operating	4,315	2,048	6,142	3,797
Taxes other than income	716	230	1,098	514
General and administrative	3,514	1,986	6,279	3,959
Depreciation, depletion and amortization	7,999	4,852	13,078	9,621
Total operating expenses	90,918	9,116	122,808	17,891
Operating income	20,436	9,616	34,736	18,804
Other income (expense)				
Interest expense	(3,081)	(1,403)	(6,195)	(2,732)
Interest income	338	256	617	524
Unrealized loss on derivatives	(828)	-	(14,764)	-
Net income	$ 16,865	$ 8,469	$ 14,394	$ 16,596
General partner's interest in net income *	$ 617	$ 169	$ 527	$ 332
Limited partner's interest in net income	$ 16,248	$ 8,300	$ 13,867	$ 16,264
Basic and diluted net income per limited partner unit, common and subordinated	$ 0.79	$ 0.46	$ 0.71	$ 0.90
Weighted average number of units outstanding, basic and diluted:				
Common	14,867	10,425	13,742	10,416
Subordinated	5,737	7,650	5,737	7,650

* The general partner's interest in net income includes the general partner's two percent interest plus the general partner's portion of incentive distribution rights.

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

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

	June 30, 2005	December 31, 2004
ASSETS	(unaudited)	
Current assets:		
Cash and cash equivalents	$ 21,619	$ 20,997
Accounts receivable	47,547	8,668
Inventory	2,055	-
Other current assets	2,835	541
Total current assets	74,056	30,206
Property and equipment	447,162	271,546
Less: Accumulated depreciation, depletion and amortization	61,012	49,931
Net property and equipment	386,150	221,615
Equity investments	28,485	27,881
Goodwill	6,931	-
Intangibles, net	38,413	-
Other long-term assets	8,282	4,733
Total assets	$ 542,317	$ 284,435
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 36,816	$ 3,989
Current portion of long-term debt	6,402	4,800
Deferred income	1,800	1,207
Derivative liabilities	11,000	-
Total current liabilities	56,018	9,996
Deferred income	9,803	8,726
Other liabilities	2,296	2,803
Derivative liabilities	8,939	-
Long-term debt	197,250	112,926
Commitments and contingencies		
Partners' capital	268,011	149,984
Total liabilities and partners' capital	$ 542,317	$ 284,435

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 June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Cash flows from operating activities				
Net income	$ 16,865	$ 8,469	$ 14,394	$ 16,596
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	7,999	4,852	13,078	9,621
Unrealized loss (gain) on derivatives, net of settlements	(1,013)	-	12,923	-
Noncash interest expense	117	126	1,342	252
Equity earnings	(246)	-	(544)	-
Changes in operating assets and liabilities	4,611	2,415	(1,415)	(336)
Net cash provided by operating activities	28,333	15,862	39,778	26,133
Cash flows from investing activities				
Acquisitions, net of cash acquired	(17,693)	-	(222,677)	-
Additions to property and equipment	(5,531)	(463)	(5,820)	(867)
Other	-	206	52	375
Net cash used in investing activities	(23,224)	(257)	(228,445)	(492)
Cash flows from financing activities				
Payments for debt issuance costs	-	-	(2,039)	-
Proceeds from borrowings	15,000	-	251,800	-
Repayments of borrowings	(9,300)	(1,000)	(165,800)	(1,000)
Proceeds from issuance of partners' capital	1,276	-	129,006	-
Distributions to partners	(13,267)	(9,593)	(23,678)	(19,269)
Net cash provided by (used in) financing activities	(6,291)	(10,593)	189,289	(20,269)
Net increase (decrease) in cash and cash equivalents	(1,182)	5,012	622	5,372
Cash and cash equivalents at beginning of period	22,801	9,426	20,997	9,066
Cash and cash equivalents at end of period	$ 21,619	$ 14,438	$ 21,619	$ 14,438
Supplemental disclosures of cash flow information				
Cash paid for interest	$ 1,856	$ 189	$ 4,961	$ 2,704
Noncash investing and financing activities				
Issuance of partners' capital for acquisition	$ -	$ -	$ -	$ 1,060

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

1. ORGANIZATION

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

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

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

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

2. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements include the accounts of Penn Virginia Resource Partners, L.P. and all wholly-owned subsidiaries. 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 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, 2004. Operating results for the six months ended June 30, 2005, are not necessarily indicative of the results that may be expected for the year ending December 31, 2005. Certain reclassifications have been made to conform to the current period's presentation.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our accounting polices are consistent with those described in our Annual Report on Form 10-K for the year ended December 31, 2004, except as discussed below. Please refer to such Form 10-K for a further discussion of those policies.

Natural Gas Midstream Revenues

Revenues from the sale of natural gas liquids ("NGLs") and residue gas are recognized when the NGLs and residue gas produced at our gas processing plants are sold. Gathering and transportation revenues are recognized based upon actual volumes delivered. Due to the time involved in gathering information from various purchasers and measurement locations and calculating 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. Since the settlement process may take up to 30 days following the month of actual production, our financial results include estimates of production and revenues for the period of actual production. Any differences, which are not expected to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized.

Goodwill

We had approximately $6.9 million of goodwill at June 30, 2005, based on the preliminary purchase price allocation for the Cantera Acquisition (as defined in Note 4). This amount may change based on the final purchase price allocation. The goodwill has been allocated to the midstream segment. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 142, *Goodwill and Other Intangible Assets*, goodwill will be assessed at least annually for impairment. We intend to test goodwill for impairment during the fourth quarter of each fiscal year.

Intangibles

Intangible assets at June 30, 2005, included $35.5 million for customer contracts and relationships and $4.6 million for rights of way. These amounts may change based on the final purchase price allocation as described in Note 4. Customer contracts and relationships are amortized on a straight-line basis over the expected useful lives of the individual contracts and relationships, which do not exceed 15 years. Rights-of-way are amortized on a straight-line basis over a period of 15 years. Total intangible amortization was approximately $1.2 million and $1.6 million during the three months and six months ended June 30, 2005, respectively. There were no intangible assets or related amortization in 2004. As of June 30, 2005, accumulated amortization of intangible assets was $1.6 million.

Aggregate amortization expense for the year ending December 31, 2005, is estimated to be approximately $4.1 million. The following table summarizes our estimated aggregate amortization expense for the next five years (in thousands):

2006	$ 4,859
2007	3,960
2008	3,339
2009	3,072
2010	2,859
Thereafter	17,863
Total	$ 35,952

4. 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 the mid-continent area of Oklahoma and the panhandle of Texas. The midstream business operates as PVR Midstream LLC, a subsidiary of Penn Virginia Operating Co., LLC, which is a wholly owned subsidiary of the Partnership. As a result of the Cantera Acquisition, we own and operate a significant set of midstream assets that include approximately 3,400 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 million cubic feet per day (MMcfd) of total capacity. Our midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We believe that the Cantera Acquisition established a platform for future growth in the natural gas midstream sector and has diversified our cash flows into another long-lived asset base. 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.

Total cash paid for the Cantera Acquisition was approximately $198 million, which we funded with a $110 million term loan and with borrowings under our revolving credit facility. The purchase price allocation for the Cantera Acquisition has not been finalized because we are still in the process of settling post-closing adjustments with the seller and obtaining final appraisals of assets acquired and liabilities assumed. We used proceeds of $129 million 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. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Cantera Acquisition based upon preliminary fair values on the date of acquisition, as follows (in thousands):

Cash consideration paid for Cantera	$ 200,594
Plus: Acquisition costs	2,740
Total purchase price	203,334
Less: Cash acquired	(5,378)
Total purchase price, net of cash acquired	$ 197,956
Current assets acquired	$ 39,148
Property and equipment acquired	145,448
Other assets acquired	645
Liabilities assumed	(34,268)
Intangible assets	40,052
Goodwill	6,931
Total purchase price, net of cash acquired	$ 197,956

The preliminary purchase price allocation includes approximately $6.9 million of goodwill. The significant factors that contributed to the recognition of goodwill include our entry into the natural gas midstream business and PVR's ability to acquire an established business with an assembled workforce. Under SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* goodwill recorded in connection with a business combination is not amortized, but rather is tested for impairment at least annually. Accordingly, the unaudited pro forma financial information presented below does not include amortization of the goodwill recorded in the acquisition. The preliminary purchase price allocation includes approximately $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 and relationships assumed, and will be reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

The following unaudited pro forma financial information reflects the consolidated results of operations of the Partnership as if the Cantera Acquisition, the closing of our amended credit facility (see Note 6) and our March 2005 public offering of common units had occurred on January 1 of the reported period. The pro forma information includes primarily adjustments 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in thousands, except share data)			
Revenues	$ 111,354	$ 84,677	$ 229,986	$ 167,149
Net income	$ 16,865	$ 9,872	$ 14,752	$ 16,758
Net income per limited partner unit, basic and diluted	$ 0.79	$ 0.47	$ 0.70	$ 0.80

5. HEDGING ACTIVITIES

Commodity Cash Flow Hedges

When we agreed to acquire Cantera, we wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a $13.9 million non-cash charge to earnings for the unrealized loss on derivatives. Subsequent to the Cantera Acquisition, we formally designated the agreements as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Upon qualifying for hedge accounting, changes in the derivative agreements' market value are accounted for as other comprehensive income or loss to the extent they are effective, rather than as a direct impact on net income. SFAS No. 133 requires us to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and we will be required to record the ineffective portion of the agreements in our net income for the respective period. Cash settlements with the counterparties related to the derivative agreements will occur monthly over the life of the agreements, with PVR receiving a correspondingly higher or lower amount for the physical sale of the commodity over the same period. Several derivative agreements for ethane, propane, crude oil and natural gas entered into subsequent to the Cantera Acquisition have been designated as cash flow hedges.

The fair values of our derivative agreements are determined based on forward price quotes for the respective commodities as of June 30, 2005. The following table sets forth our positions as of June 30, 2005:

	Average Volume Per Day	**Weighted Average Price**	**Estimated Fair Value (in thousands)**
Ethane Swaps	**(in gallons)**	**(per gallon)**	$ (2,910)
Third Quarter 2005 through Fourth Quarter 2006	68,880	$0.4770	
First Quarter 2007 through Fourth Quarter 2007	34,440	$0.5050	
First Quarter 2008 through Fourth Quarter 2008	34,440	$0.4700	
Propane Swaps	**(in gallons)**	**(per gallon)**	(4,725)
Third Quarter 2005 through Fourth Quarter 2006	52,080	$0.7060	
First Quarter 2007 through Fourth Quarter 2007	26,040	$0.7550	
First Quarter 2008 through Fourth Quarter 2008	26,040	$0.7175	
Crude Oil Swaps	**(in Bbls)**	**(per Bbl)**	(11,456)
Third Quarter 2005 through Fourth Quarter 2006	1,100	$44.45	
First Quarter 2007 through Fourth Quarter 2007	560	$50.80	
First Quarter 2008 through Fourth Quarter 2008	560	$49.27	
Natural Gas Swaps	**(in MMbtu)**	**(per MMbtu)**	4,472
Third Quarter 2005 through Fourth Quarter 2006	7,500	$7.0527	
First Quarter 2007 through Fourth Quarter 2008	4,000	$6.9675	
			$ (14,619)

Based upon our assessment of our derivative agreements designated as cash flow hedges at June 30, 2005, we reported (i) a net derivative liability of approximately $14.6 million, (ii) a loss in accumulated other comprehensive income of $1.7 million and (iii) an unrealized loss on derivatives of $0.8 million for hedge ineffectiveness. In connection with monthly settlements, we recognized net hedging gains in natural gas midstream revenues of $0.8 million for the three months and six months ended June 30, 2005, and net hedging losses in cost of gas purchased of $0.2 million for the three months and six months ended June 30, 2005. Based upon future commodity prices as of June 30, 2005, $8.3 million of hedging losses are expected to be realized within the next 12 months. The amounts that we will ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. Because all hedged volumes relate to periods beginning after March 31, 2005, we had no monthly settlements and recognized no net hedging losses in natural gas midstream revenues in 2004.

Interest Rate Swap

In connection with the issuance of our senior unsecured notes (see Note 6), we entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of those notes. The notional amount decreased by one-third of each principal payment. Under the terms of the interest rate swap agreement, the counterparty paid a fixed rate of 5.77 percent on the notional amount and received a variable rate equal to the floating interest rate which was determined semi-annually and was based on the six month London Interbank Offering Rate plus 2.36 percent. Settlements on the swap were recorded as interest expense. In conjunction with the closing of the Cantera Acquisition on March 3, 2005, we entered into an amendment to the senior unsecured notes in which we agreed to a 0.25 percent increase in the fixed interest rate on the senior unsecured notes, from 5.77 percent to 6.02 percent. This swap was designated as a fair value hedge because it had been determined that it was highly effective in mitigating the change in fair value of the hedged portion of the notes.

The interest rate swap agreement was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by us to the counterparty in July 2005. The fair market value of the interest rate swap agreement as of June 30, 2005, is included in current derivative liabilities on the balance sheet.

6. LONG-TERM DEBT

At June 30, 2005, and December 31, 2004, long-term debt consisted of the following (in thousands):

	June 30, 2005 (Unaudited)	December 31, 2004
Senior unsecured notes*	$ 86,152	$ 87,726
Revolving credit facility	117,500	30,000
	203,652	117,726
Less: Current maturities	(6,402)	(4,800)
	$ 197,250	$ 112,926

* Includes a negative fair value adjustment of $0.8 million as of June 30, 2005, and December 31, 2004, related to an interest rate swap designated as a fair value hedge.

Concurrent with the closing of the Cantera Acquisition, 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 consisting of a $150 million revolving credit facility that matures in March 2010 and a $110 million term loan. As of June 30, 2005, the new credit agreement consisted of a $150 million revolving credit facility. A portion of the revolving credit facility and the term loan were used to fund the Cantera Acquisition and to repay borrowings under our previous credit facility. Proceeds of $129 million, including a $2.6 million contribution from our general partner, received from a subsequent public offering of 2.5 million common units in March 2005 were used to repay the $110 million term loan and a portion of the amount outstanding under the revolving credit facility. The term loan cannot be re-borrowed. The revolving credit facility 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. As of June 30, 2005, we had a one-time option under the revolving credit facility to increase the facility by an additional $100 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders.

In July 2005, we amended the credit agreement to increase the size of the revolving credit facility from $150 million to $300 million. We increased the one-time option under the revolving credit facility to expand the facility by an additional $150 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders. The amendment also updated certain debt covenant definitions. The interest rate under the credit agreement remained unchanged and will fluctuate based on the Partnership's ratio of total indebtedness to EBITDA. At our option, interest shall be payable at a base rate plus an applicable margin ranging up to 1.00 percent or a rate derived from the London Interbank Offering Rate plus an applicable margin ranging from 1.00 percent to 2.00 percent. Other terms of the credit agreement remained unchanged.

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

Upon settlement of the interest rate swap agreement (see Note 5), the $0.8 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the Notes using the interest rate method.

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

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, no related liabilities are accrued.

8. NET INCOME PER LIMITED PARTNER UNIT

Basic and diluted net income per limited partner unit is computed by dividing net income attributable to limited partners, after deducting the general partner's two percent interest and incentive distributions, by the weighted average number of outstanding common units and subordinated units. At June 30, 2005, there were no dilutive units outstanding.

9. RELATED PARTY TRANSACTION

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 the Partnership. Total corporate administrative expenses charged to the Partnership totaled $0.5 million and $0.4 million for the three months ended June 30, 2005 and 2004, respectively, and $0.9 million and $0.7 million for the six months ended June 30, 2005 and 2004, respectively. 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.

10. DISTRIBUTIONS

We make quarterly cash distributions of our available cash, generally defined as consolidated cash receipts less consolidated cash disbursements and cash reserves established by the 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:

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

The following table reflects the allocation of total cash distributions paid during the six months ended June 30, 2005 (in thousands, except per unit information):

Limited partner units	$	22,949
General partner ownership interest		434
General partner incentive		295
Total cash distributions	$	23,678
Total cash distributions paid per unit	$	1.1825

In May 2005, we paid a quarterly distribution of $0.62 per unit. The first $0.55 per unit was paid 98 percent to all units, pro rata, and two percent to the general partner. The amount in excess of $0.55 per unit, or $0.07 per unit, was paid 85 percent to all units, pro rata, and 15 percent to the general partner. In July 2005, we announced a $0.65 per unit distribution for the three months ended June 30, 2005, or $2.60 per unit on an annualized basis. The distribution will be paid on August 12, 2005, to unitholders of record on August 2, 2005. The first $0.55 per unit will be paid 98 percent to all units, pro rata, and two percent to the general partner. The amount in excess of $0.55 per unit, or $0.10 per unit, will be paid 85 percent to all units, pro rata, and 15 percent to the general partner.

11. COMPREHENSIVE INCOME

Comprehensive income represents changes in partners' capital during the reporting period, including net income and charges directly to partners' capital which are excluded from net income. For the three months and six months ended June 30, 2005 and 2004, the components of comprehensive income were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net income	$ 16,865	$ 8,469	$ 14,394	$ 16,596
Unrealized holding gains (losses) on hedging activities	1,621	-	(1,105)	-
Reclassification adjustment for hedging activities	(591)	-	(591)	-
Comprehensive income	$ 17,895	$ 8,469	$ 12,698	$ 16,596

12. SEGMENT INFORMATION

Segment information has been prepared in accordance with SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.* Under SFAS No. 131, operating segments are defined as components of an enterprise about which separate financial information is available and is evaluated regularly by the chief operating decision maker, or decision-making group, in assessing performance. Our chief operating decision-making group consists of our Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our 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 region of the United States and New Mexico;
- other land management activities such as selling standing timber and real estate rentals;
- fee-based infrastructure facilities leased to certain lessees; and
- our investment in a joint venture which primarily provides coal handling facilities to end-user industrial plants.

Natural Gas Midstream

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

In our Annual Report on Form 10-K for the year ended December 31, 2004, we reported two segments – coal royalty and coal services. As a result of the Cantera Acquisition, our Chief Executive Officer and other senior officials now review the operating results of our coal business on an aggregated basis. Accordingly, we now report the coal and natural gas midstream businesses as our two segments. The following segment information for the three months and six months ended June 30, 2004, has been restated to conform to the current period's presentation. The following is a summary of certain financial information relating to the Partnership's segments (in thousands):

	Coal	Natural Gas Midstream	Consolidated
For the Three Months Ended June 30, 2005:			
Revenues	$ 23,693	$ 87,661	$ 111,354
Cost of gas purchased	-	74,374	74,374
Operating costs and expenses	3,063	5,482	8,545
Depreciation, depletion and amortization	4,328	3,671	7,999
Operating income	$ 16,302	$ 4,134	$ 20,436
Interest expense, net			(2,743)
Unrealized loss on derivatives			(828)
Net income			$ 16,865
Total assets	$ 288,278	$ 254,039	$ 542,317
Additions to property and equipment and acquisitions, net of cash acquired	$ 19,659	$ 3,565	$ 23,224
For the Three Months Ended June 30, 2004:			
Revenues	$ 18,732	$ -	$ 18,732
Operating costs and expenses	4,264	-	4,264
Depreciation, depletion and amortization	4,852	-	4,852
Operating income	$ 9,616	$ -	$ 9,616
Interest expense, net			(1,147)
Net income			$ 8,469
Total assets	$ 258,722	$ -	$ 258,722
Additions to property and equipment and acquisitions, net of cash acquired	$ 463	$ -	$ 463

	Coal	(a) Natural Gas Midstream	Consolidated
For the Six Months Ended June 30, 2005:			
Revenues	$ 43,505	$ 114,039	$ 157,544
Cost of gas purchased	-	96,211	96,211
Operating costs and expenses	6,726	6,793	13,519
Depreciation, depletion and amortization	8,183	4,895	13,078
Operating income	$ 28,596	$ 6,140	$ 34,736
Interest expense, net			(5,578)
Unrealized loss on derivatives			(14,764)
Net income			$ 14,394
Total assets	$ 288,278	$ 254,039	$ 542,317
Additions to property and equipment and acquisitions, net of cash acquired	$ 29,031	$ 199,466	$ 228,497
For the Six Months Ended June 30, 2004:			
Revenues	$ 36,695	$ -	$ 36,695
Operating costs and expenses	8,270	-	8,270
Depreciation, depletion and amortization	9,621	-	9,621
Operating income	$ 18,804	$ -	$ 18,804
Interest expense, net			(2,208)
Net income			$ 16,596
Total assets	$ 258,722	$ -	$ 258,722
Additions to property and equipment and acquisitions, net of cash acquired (b)	$ 1,927	$ -	$ 1,927

(a) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(b) Includes noncash expenditures of $1.1 million.

13. RECENT ACCOUNTING PRONOUNCEMENTS

In March 2005, the Financial Accounting Standards Board (the "FASB") released Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), which provides guidance for applying SFAS No. 143, *Accounting for Asset Retirement Obligations.* FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year companies). We expect no change to our results of operations or financial position as a result of implementing FIN 47.

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

14. SUBSEQUENT EVENTS

Wayland Acquisition

In July 2005, we acquired a combination of fee ownership and lease rights to approximately 15 million tons of coal reserves for approximately $14 million (the "Wayland Acquisition"). The reserves are located in Knott County in eastern Kentucky. The acquisition was funded with $4 million of cash and our issuance to the seller of approximately 209,000 common units. During the third quarter of 2005, we expect to begin construction of a new preparation plant and unit train coal loading facility on the property, with completion expected during the second quarter of 2006 at an estimated additional capital expenditure of approximately $12.5 million. The reserves have been leased to an operator who will commence the mining of raw coal on a limited basis during construction of the preparation and loading facility. After completion of the facility, the operator's production from the property is expected to increase to approximately one million tons of coal per year starting in 2007. We also expect to earn fees from third party operators for coal processed from adjacent properties.

Green River Acquisition

In July 2005, we also acquired fee ownership of approximately 95 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for approximately $62 million in cash (the "Green River Acquisition"). This coal reserve acquisition is our first in the Illinois Basin and was funded using our recently expanded credit facility. Currently, approximately 45 million tons of these coal reserves are leased to affiliates of Peabody Energy (NYSE:BTU). 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.

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," "our" or "us") should be read in conjunction with our Consolidated Financial Statements and Notes thereto.

Overview

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. Since the acquisition of a natural gas midstream business in March 2005, we conduct operations in two business segments: coal and natural gas midstream.

Coal Segment Overview

In our coal royalty and land leasing operations, 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. For the six months ended June 30, 2005, our lessees produced 14.0 million tons of coal from our properties and paid us coal royalty revenues of $38.2 million, for an average gross coal royalty per ton of $2.73. Approximately 82 percent of our coal royalty revenues for the first six months of 2005 and 78 percent of our coal royalty revenues for the first six months of 2004 were derived from coal mined on our properties and sold by our lessees multiplied by a royalty rate per ton resulting from the higher of a percentage of the gross sales price or a fixed price per ton of coal, with pre-established minimum monthly or annual rental payments. The balance of our coal royalty revenues for the respective periods was derived from coal mined on two of our properties under leases containing fixed royalty rates per ton of coal mined and sold. The royalty rates under those leases escalate annually, with pre-established minimum monthly payments. 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. Included in our coal royalty and land leasing operations are revenues earned from the sale of standing timber on our properties. In our coal services operations, we generate revenues from providing fee-based coal preparation and transportation services to our lessees, which enhance their production levels and generate additional coal royalty revenues. We also earn revenues from third party end-users by owning and operating coal handling facilities through our joint venture with Massey Energy Company.

As of June 30, 2005, our coal reserves, coal infrastructure and timber assets were located on the following properties:

* in central Appalachia:
  - the Wise property, located in Wise and Lee Counties, Virginia, and Letcher and Harlan Counties, Kentucky;
  - the Coal River property, located in Boone, Fayette, Kanawha, Lincoln and Raleigh Counties, West Virginia;
  - the Spruce Laurel property, located in Boone and Logan Counties, West Virginia;
  - the Buchanan property, located in Buchanan County, Virginia;
* the northern Appalachia property, located in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia; and
* the New Mexico property, located in McKinley County, New Mexico;

Our revenues and profitability will be adversely affected in the future if we are unable to replace or increase our reserves through acquisitions. Our management continues to focus on acquisitions of assets and energy sources necessary to meet the requirements of diverse markets and environmental regulations. We added personnel in 2003 to evaluate acquisitions of coal reserves and coal industry-related infrastructure, and we completed two acquisitions in the first six months of 2005.

In July 2005, we completed the acquisitions of two additional properties containing an aggregate of approximately 110 million tons of coal reserves for total consideration of approximately $76 million. These acquisitions are discussed further under “Acquisitions and Investments” below.

Natural Gas Midstream Segment Overview

On March 3, 2005, we completed the acquisition of Cantera Gas Resources, LLC (“Cantera”), a midstream gas gathering and processing company with primary locations in the mid-continent area of Oklahoma and the panhandle of Texas (the “Cantera Acquisition”). As a result of the Cantera Acquisition, we own and operate a significant set of midstream assets that includes approximately 3,400 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 million cubic feet per day (MMcfd) of total capacity. Our midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. Cantera Acquisition also includes a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems, such as Enogex and ONEOK, and at market hubs accessed by various interstate pipelines. We believe that the Cantera Acquisition established a platform for future growth in the natural gas midstream sector and has diversified our cash flows into another long-lived asset base. The total cash paid for the Cantera Acquisition was approximately $198 million, which we funded with a $110 million term loan and with borrowings 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.

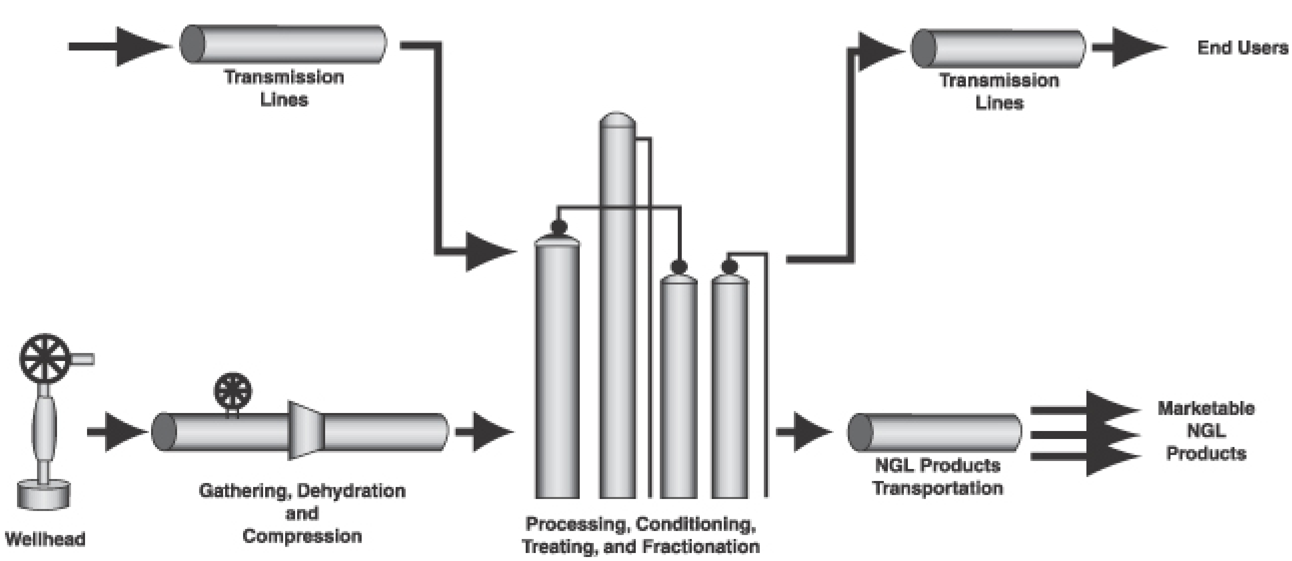
The following table sets forth information regarding our midstream assets:

Asset	Type	Approximate Length (Miles)	Approximate Wells Connected	Processing Capacity (Mmcfd)[1]	Year Ended December 31, 2004 Average Plant Throughput (Mmcfd)	Year Ended December 31, 2004 Utilization of Processing Capacity (%)
Beaver/Perryton System	Gathering pipelines and processing facility	1,160	664	100	80.9	80.9%
Crescent System	Gathering pipelines and processing facility	1,670	804	40	19.3	48.3%
Hamlin System	Gathering pipelines and processing facility	515	857	20	5.1	25.5%
Arkoma System	Gathering pipelines	78	56	—	16.9[2][3]	—
					122.2	

(1) Many capacity values are based on current operating configurations and could be increased through additional compression, increased delivery meter capacity and/or other facility upgrades.
(2) Gathering only volumes.
(3) Reported in MMBtu.

The natural gas midstream industry is the link between the production of natural gas and the delivery of its components to end-use markets. It consists of natural gas gathering, dehydration, compression, treating, processing and transportation and natural gas liquid ("NGL") extraction, fractionation and transportation. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

Of the services illustrated in the following diagram, we provide natural gas gathering, dehydration, compression, processing, transportation and related services to our customers.



These services are described below:

- *Natural Gas Gathering*. The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, it is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from the wells and transport it to larger pipelines for further transportation.
- *Natural Gas Compression*. Gathering systems are designed to maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and continue to produce for longer periods of time. As the pressure of a well declines, it becomes more difficult to deliver its production into a higher pressure gathering system. Field compression is typically used to lower the pressure of a gathering system.
- *Natural Gas Dehydration*. As produced, some natural gas is saturated with water, which must be removed because the combination of natural gas and water can form ice that can plug the pipeline system. Water in a natural gas stream can also cause corrosion when combined with carbon dioxide or hydrogen sulfide in natural gas, and condensed water in the pipeline can raise pipeline pressure. To avoid these potential issues and to meet downstream pipeline and end-user gas quality standards, natural gas is dehydrated to remove the excess water.
- *Natural Gas Treating*. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations can be high in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove contaminants from natural gas to ensure that it meets pipeline quality specifications. We do not currently treat natural gas.
- *Natural Gas Processing and Conditioning.* Some natural gas production does not meet pipeline quality specifications or is not suitable for commercial use and must be processed to remove the NGLs. In addition, some natural gas, while not required to be processed, can be processed to take advantage of favorable processing margins.
- *Natural Gas Fractionation*. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Isobutane is primarily used to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient in synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock. We do not own or operate fractionation facilities.
- *Natural Gas Transportation*. Natural gas transportation pipelines receive natural gas from gathering systems and other mainline transportation pipelines and deliver the natural gas to industrial end-users, utilities and other pipelines.

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.

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;
- the relative volumes of gas lost through leakage and operating inefficiencies;
- the accuracy in measuring volume throughout the system;
- 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 based on the producer concerns listed above. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas.

Acquisitions and Investments

Capital expenditures, including noncash items, were as follows:

	Six Months Ended June 30, 2005	2004
	(in thousands)	
Acquisition of natural gas midstream business, net of cash acquired	$ 197,956	$ -
Acquisitions of coal reserves *	24,721	1,132
Coal services and land management additions	-	763
Other property and equipment expenditures	5,820	32
Total capital expenditures	$ 228,497	$ 1,927

* Amount in 2004 includes noncash expenditure of $1.1 million to acquire additional reserves on our northern Appalachia properties in exchange for equity issued in the form of Partnership common and Class B units.

Cantera Acquisition

On March 3, 2005, we completed our acquisition of Cantera, a midstream gas gathering and processing company with primary locations in the mid-continent area of Oklahoma and the panhandle of Texas. See the description of the Cantera Acquisition in "Natural Gas Midstream Segment Overview" above. The total cash paid for the Cantera Acquisition was approximately $198 million, which we funded with a $110 million term loan and with borrowings under our revolving credit facility. The purchase price allocation for the Cantera Acquisition has not been finalized. 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 4 in the Notes to Consolidated Financial Statements for pro forma financial information.

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 (the "Coal River Acquisition"). The coal reserves are located in central Appalachia, adjacent to the Bull Creek tract on our Coal River property in 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; development will occur in conjunction with our Bull Creek reserves and loadout facility that was placed into service in 2004. The oil and gas property contains approximately 2.8 billion cubic feet equivalent of net proved oil and gas reserves and current net production of approximately 166 million cubic feet equivalent on an annualized basis.

Alloy Acquisition

In April 2005, we acquired fee ownership of approximately 13 million tons of coal reserves for $15 million (the "Alloy Acquisition"). The reserves, located on approximately 8,300 acres in the Central Appalachian region of West Virginia, will be produced from deep and surface mines with production anticipated to start in late 2005. Revenues will be earned initially from transportation-related fees on coal mined from an adjacent property, followed by royalty revenues as the mines commence production. The seller will remain on the property as the lessee and operator. The acquisition was funded with long-term debt under our revolving credit facility.

Wayland Acquisition

In July 2005, we acquired a combination of fee ownership and lease rights to approximately 15 million tons of coal reserves for approximately $14 million (the "Wayland Acquisition"). The reserves are located in Knott County in the eastern Kentucky portion of central Appalachia. The acquisition was funded with $4 million of cash and our issuance of approximately 209,000 common units. During the third quarter of 2005, we expect to begin construction of a new preparation plant and unit train coal loading facility on the property, with completion expected during the second quarter of 2006 at an estimated additional capital expenditure of approximately $12.5 million. The reserves have been leased to an operator who will commence the mining of raw coal on a limited basis during construction of the preparation and loading facility. After completion of the facility, the operator's production from the property is expected to increase to approximately one million tons of coal per year starting in 2007. We also expect to earn fees from third party operators for coal processed from adjacent properties.

Green River Acquisition

In July 2005, we also acquired fee ownership of approximately 95 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for approximately $62 million of cash (the "Green River Acquisition"). This coal reserve acquisition is our first in the Illinois Basin and was funded using our recently expanded credit facility. Currently, approximately 45 million tons of these coal reserves are leased to affiliates of Peabody Energy (NYSE:BTU). 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.

Critical Accounting Policies and Estimates

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 involved in gathering information from various purchasers and measurement locations and calculating 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 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 are not expected to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Depletion. Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable reserves have been estimated by our own geologists and outside consultants. Our estimates of coal reserves are updated annually and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. We estimate timber inventory using statistical information and data obtained from physical measurements, site maps, photo-types and other information gathering techniques. These estimates are updated annually and may result in adjustments of timber volumes and depletion rates, which are recognized prospectively.

Goodwill. Under Statement of Financial Accounting Standards ("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 intend to test goodwill for impairment during the fourth quarter of each fiscal year.

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

Results of Operations

Selected Financial Data – Consolidated

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(in thousands, except share data)		(in thousands, except share data)	
Revenues	$ 111,354	$ 18,732	$ 157,544	$ 36,695
Operating expenses	$ 90,918	$ 9,116	$ 122,808	$ 17,891
Operating income	$ 20,436	$ 9,616	$ 34,736	$ 18,804
Net income	$ 16,865	$ 8,469	$ 14,394	$ 16,596
Net income per limited partner unit, basic and diluted	$ 0.79	$ 0.46	$ 0.71	$ 0.90
Cash flows provided by operating activities	$ 28,333	$ 15,862	$ 39,778	$ 26,133

The decrease in net income for the six months ended June 30, 2005, compared to the same period in 2004 was primarily attributable to $14.8 million in non-cash charges to earnings for unrealized losses on derivatives in our natural gas midstream segment and a $3.5 million increase in interest expense, partially offset by a $15.9 million, or 85 percent, increase in operating income. The increase in net income for the three months ended June 30, 2005, compared to the same period in 2004 was primarily attributable to a $10.8 million increase in operating income, partially offset by a $0.8 million non-cash charge to earnings for unrealized ineffectiveness losses on derivatives in our natural gas midstream segment and a $1.7 million increase in interest expense. Operating income increased in both the three months and six months ended June 30, 2005, 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 our coal reserves, timber assets and other land assets. We enter into leases with various third-party operators for the right to mine coal reserves on our properties in exchange for royalty payments. We do not operate any mines. In addition to coal royalty revenues, we generate coal services revenues from fees charged to lessees for the use of coal preparation and transloading facilities. We also generate revenues from the sale of standing timber on our properties.

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 June 30, 2005, Compared with Three Months Ended June 30, 2004

Financial Highlights	Three Months Ended June 30, 2005 (in thousands)	Three Months Ended June 30, 2004 (in thousands)	Percentage Change
Revenues			
Coal royalties	$ 20,129	$ 17,517	15%
Coal services	1,338	942	42%
Timber	117	142	(18%)
Other	2,109	131	1,510%
Total revenues	23,693	18,732	26%
Operating costs and expenses			
Operating	1,141	2,048	(44%)
Taxes other than income	230	230	-
General and administrative	1,692	1,986	(15%)
Depreciation, depletion and amortization	4,328	4,852	(11%)
Total operating expenses	7,391	9,116	(19%)
Operating income	$ 16,302	$ 9,616	70%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	7,250	7,941	(9%)
Average royalty per ton ($/ton)	$ 2.78	$ 2.21	26%

Revenues. Coal royalty revenues increased due to higher royalties per ton despite a decrease in production. Average royalties per ton increased to $2.78 in the second quarter of 2005 from $2.21 in the comparable 2004 period. The increase in the average royalties per ton was primarily due to stronger market conditions for coal and the resulting higher coal prices. Production decreased by nine percent primarily as a result of the factors discussed below.

* Production on the Coal River property decreased by 0.4 million tons. One lessee moved its longwall mining to an adjacent property from one of our subleased properties during the first quarter of 2005, resulting in a decrease of 0.8 million tons of coal production. Partially offsetting this production decrease was an increase at our West Coal River property where operations commenced in third quarter 2003, and production has steadily increased, contributing an additional 0.1 million tons in the second quarter of 2005 compared to the second quarter of 2004. Despite the net decrease in production, revenues increased by $0.9 million due to pricing improvement. Increased demand fueled a coal sales price increase in the region, which in turn resulted in a 46 percent increase in our average gross royalty per ton on the Coal River property, from $2.53 per ton in the second quarter of 2004 to $3.69 per ton in the second quarter of 2005.

* Production on the Wise property decreased by 0.1 million tons, primarily as a result of the termination of a surface mine by one of our lessees and adverse mining conditions, but revenues increased by $1.63 million. The revenue increase was primarily due to an increase in the average royalty per ton received from our lessees. Increased coal sales prices fueled by stronger demand in the region resulted in higher price realizations by our lessees. This caused a 23 percent increase in the average gross royalty per ton from $2.73 per ton in the second quarter of 2004 to $3.35 per ton in the second quarter of 2005.

* Production on the Spruce Laurel property remained consistent from second quarter 2004 to second quarter 2005, with a decrease in production at one mine due to adverse mining conditions being offset by production from a new mine. Revenues increased by $0.3 million, primarily due to increased coal sales prices fueled by a stronger demand in the region. The higher royalty revenues received from our lessees resulted in a 31 percent increase in the average gross royalty per ton on the Spruce Laurel property, from $2.52 per ton in the second quarter of 2004 to $3.30 per ton in the second quarter of 2005.

* Production on our Northern Appalachian properties remained consistent from second quarter 2004 to second quarter 2005. Increased coal sales prices fueled by a stronger demand in the region caused revenues to increase by $0.2 million, resulting in a nine percent increase in the average royalty per ton from $1.31 in the second quarter of 2004 to $1.43 in the second quarter of 2005.

* Production on the New Mexico property decreased by 0.3 million tons due to the inability of our lessee's customer to receive shipments because of an operating problem at its power generation facility.

Coal services revenues increased primarily as a result of equity earnings from the coal handling joint venture we acquired in July 2004 and start-up operations at our West Coal River and Bull Creek facilities in July 2003 and February 2004, respectively.

Other revenues increased primarily due to $1.5 million received 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 also began receiving additional transportation-related fees in the second quarter of 2005 as a result of the Alloy Acquisition in April 2005.

Operating Costs and Expenses. The decrease in aggregate operating costs and expenses primarily relates to decreases in operating expenses, general and administrative expenses and depreciation, depletion and amortization ("DD&A").

Operating expenses decreased due to a decrease in royalty expense resulting from decreased production on the subleased portion of the Coal River property as previously described in the "Revenues" paragraphs above.

DD&A expense decreased primarily as a result of lower production.

Six Months Ended June 30, 2005, Compared with Six Months Ended June 30, 2004

Financial Highlights	Six Months Ended June 30, 2005 (in thousands)	Six Months Ended June 30, 2004 (in thousands)	Percentage Change
Revenues			
Coal royalties	$ 38,182	$ 34,377	11%
Coal services	2,608	1,726	51%
Timber	336	295	14%
Other	2,379	297	701%
Total revenues	43,505	36,695	19%
Operating costs and expenses			
Operating	2,173	3,797	(43%)
Taxes other than income	508	514	(1%)
General and administrative	4,045	3,959	2%
Depreciation, depletion and amortization	8,183	9,621	(15%)
Total operating expenses	14,909	17,891	(17%)
Operating income	$ 28,596	$ 18,804	52%
Operating Statistics			
Royalty coal tons produced by lessees (tons in thousands)	13,965	15,894	(12%)
Average royalty per ton ($/ton)	$ 2.73	$ 2.16	26%

Revenues. Coal royalty revenues increased due to higher royalties per ton despite a decrease in production. Average royalties per ton increased to $2.73 in the first six months of 2005 from $2.16 in the comparable 2004 period. The increase in the average royalties per ton was primarily due to stronger market conditions for coal and the resulting higher coal prices. Production decreased by 12 percent primarily as a result of the factors discussed below.

* Production on the Coal River property decreased by 0.9 million tons. One lessee moved its longwall mining to an adjacent property from one of our subleased properties during the first quarter of 2005, resulting in a decrease of 1.6 million tons of coal production. Partially offsetting this production decrease

was an increase at our West Coal River property where operations commenced in third quarter 2003, and production has steadily increased, contributing an additional 0.3 million tons in the first half of 2005 compared to the first half of 2004. Despite the net decrease in production, revenues increased by $0.5 million due to pricing improvement. Increased demand fueled a coal sales price increase in the region, which in turn resulted in a 35 percent increase in our average gross royalty per ton on the Coal River property, from $2.52 per ton in the first half of 2004 to $3.40 per ton in the first half of 2005.

* Production on the Wise property decreased by 0.3 million tons, primarily as a result of the termination of a surface mine by one of our lessees and adverse mining conditions. Despite this production decrease, revenues increased by $2.7 million. The revenue increase was primarily due to an increase in the average royalty per ton received from our lessees. Increased coal sales prices fueled by stronger demand in the region resulted in higher price realizations by our lessees. This caused a 28 percent increase in the average gross royalty per ton from $2.60 per ton in the first half of 2004 to $3.34 per ton in the first half of 2005.

* Production on the Spruce Laurel property remained consistent from the first half of 2004 to the first half of 2005, with a decrease in production at one mine due to adverse mining conditions being offset by production from a new mine. Revenues increased by $0.7 million, primarily due to increased coal sales prices fueled by a stronger demand in the region. The higher royalty revenues received from our lessees resulted in a 33 percent increase in the average gross royalty per ton on the Spruce Laurel property, from $2.49 per ton in the first half of 2004 to $3.31 per ton in the first half of 2005.

* Production on our Northern Appalachian properties decreased by 0.2 million tons, due to timing of sales. Lessees continue to mine coal, but that coal is being placed in inventory rather than being sold. Revenues increased by $0.1 million due to a 10 percent increase in the average royalty per ton from $1.31 in the first half of 2004 to $1.44 in the first half of 2005.

* Production on the New Mexico property decreased by 0.6 million tons due to the inability of our lessee's customer to receive shipments because of an operating problem at its power generation facility.

Coal services revenues increased primarily as a result of equity earnings from the coal handling joint venture we acquired in July 2004 and start-up operations at our West Coal River and Bull Creek facilities in July 2003 and February 2004, respectively.

Other revenues increased primarily due to $1.5 million received 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 also began receiving additional transportation-related fees in the second quarter of 2005 as a result of the Alloy Acquisition in April 2005.

Operating Costs and Expenses. The decrease in aggregate operating costs and expenses primarily relates to decreases in operating expenses and DD&A.

Operating expenses decreased due to a decrease in royalty expense resulting from decreased production on the subleased portion of the Coal River property as previously described in the "Revenues" paragraphs above.

DD&A expense decreased primarily as a result of lower production.

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 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.

Operations and Financial Summary – Natural Gas Midstream Segment

	Three Months Ended June 30, 2005		Six Months Ended June 30, 2005*	
	Amount (in thousands)	(per Mcf)	Amount (in thousands)	(per Mcf)
Financial Highlights				
Revenues				
Residue gas	$ 44,806		$ 61,846	
Natural gas liquids	36,720		44,995	
Condensate	3,364		3,364	
Gathering and transportation fees	2,105		3,068	
Marketing revenue, net	666		766	
Total revenues	87,661	$ 7.63	114,039	$ 7.41
Operating costs and expenses				
Cost of gas purchased	74,374	6.47	96,211	6.25
Operating	3,174	0.28	3,969	0.26
Taxes other than income	486	0.04	590	0.04
General and administrative	1,822	0.16	2,234	0.14
Depreciation and amortization	3,671	0.32	4,895	0.32
Total operating expenses	83,527	7.27	107,899	7.01
Operating income	4,134	$ 0.36	6,140	$ 0.40
Operating Statistics				
Inlet volumes (MMcf)	11,489		15,396	
Midstream processing margin **	$ 12,621	$ 1.10	$ 17,062	$ 1.11

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

** Midstream processing margin consists of total revenues minus marketing revenues, net, and the cost of gas purchased.

Revenues. Revenues for the three months and six months ended June 30, 2005, included residue gas sold from processing plants after NGLs have been removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from volumes connected to our gas processing plants and the purchase and resale of natural gas not connected to the gathering systems and processing plants.

Average realized sales prices were $7.57 per thousand cubic feet (Mcf) in the three months ended June 30, 2005, and $7.36 per Mcf in the six months ended June 30, 2005. Natural gas inlet volumes at our three gas processing plants were approximately 11.5 billion cubic feet (Bcf) and 15.4 Bcf during the three months and six months ended June 30, 2005, respectively.

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

Cost of gas purchased for the three months and six months ended June 30, 2005, consisted of amounts paid to third-party producers for gas purchased under percentage of proceeds and keep-whole contracts. The average purchase price for gas was $6.47 per Mcf in the three months ended June 30, 2005, and $6.25 per Mcf in the six months ended June 30, 2005. The midstream processing margin, consisting of total revenues minus marketing revenues and the cost of gas purchased, was $12.6 million, or $1.10 per Mcf of inlet gas, in the three months ended June 30, 2005, and $17.1 million, or $1.11 per Mcf of inlet gas, in the six months ended June 30, 2005.

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

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

Depreciation and amortization expense for the three months and six months ended June 30, 2005, included $1.2 million and $1.6 million, respectively, in amortization of intangibles recognized in connection with the Cantera Acquisition and $2.5 million and $3.3 million, respectively, of depreciation on property, plant and equipment.

Other

Interest expense for the three months and six months ended June 30, 2005, increased compared to the same periods in 2004 primarily due to interest incurred on additional borrowings on our revolving credit facility and a new term loan in March 2005 to finance the Cantera Acquisition.

The non-cash unrealized loss on derivatives primarily represents the change in the market value of derivative agreements between the time we entered into the agreements in January 2005 and the time they qualified for hedge accounting after closing the Cantera Acquisition in March 2005. When we agreed to acquire Cantera, we wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a non-cash charge to earnings for the unrealized loss on derivatives. Upon qualifying for hedge accounting, changes in the derivative agreements' market value are accounted for as other comprehensive income or loss to the extent they are effective rather than a direct effect on net income. Cash settlements with the counterparties related to the derivative agreements will occur monthly in the future over the life of the agreements, with PVR receiving a correspondingly higher or lower amount for the physical sale of the commodity over the same period.

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 distributions to our general partner and unitholders, normal operating expenses, interest and principal payments on our long-term debt and acquisitions of new assets or businesses.

Cash Flows. Net cash provided by operating activities was $39.8 million in the first six months of 2005 compared with $26.1 million in the first six months of 2004. The increase was largely due to higher average gross royalties per ton and accretive cash flows from our newly acquired natural gas midstream segment.

Net cash used in investing activities was $228.4 million in the first six months of 2005 compared with $0.5 million in first six months of 2004. Cash used in investing activities for the six months ended June 30, 2005, primarily related to $198 million paid for the Cantera Acquisition, net of cash received and including capitalized acquisition costs. The balance of cash used in investing activities represents the $9 million Coal River Acquisition, the $15 million Alloy Acquisition, and the $4 million acquisition of railcars that we previously leased. Net cash used in investing activities for the six months ended June 30, 2004, primarily related to the completion of a new coal loading facility on our Coal River property in West Virginia and two smaller infrastructure projects.

Net cash provided by financing activities was $189.3 million in the first six months of 2005 compared with $20.3 million used in financing activities in the first six months of 2004. We had borrowings, net of repayments, of $86 million in the first six months of 2005 to finance the Cantera Acquisition, compared to $1.0 million of net repayments in the first six months of 2004. We received proceeds of $129 million from our sale of common units in a public offering which was completed in March 2005. As a result of the public offering, distributions to partners increased to $23.7 million for the first six months of 2005 from $19.3 million in the same period of 2004.

In July 2005, we announced a $0.65 per unit quarterly distribution for the three months ended June 30, 2005, or $2.60 per unit on an annualized basis. The distribution will be paid on August 12, 2005, to unitholders of record on August 2, 2005. The distribution represents a 20 percent increase over the $0.54 per unit distribution paid for the three months ended June 30, 2004.

Long-Term Debt. As of June 30, 2005, we had outstanding borrowings of $203.7 million, consisting of $117.5 million borrowed under our revolving credit facility and $86.2 million of senior unsecured notes (the "Notes"). The current portion of the Notes as of June 30, 2005, was $6.4 million.

Concurrent with the closing of the Cantera Acquisition, 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 that matures in March 2010. As of June 30, 2005, the new credit agreement consisted of a $150 million revolving credit facility. A portion of the revolving credit facility and a $110 million term loan were used to fund the Cantera Acquisition and to repay borrowings under our previous credit facility. The revolving credit facility 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. As of June 30, 2005, we had a one-time option under the revolving credit facility to increase the facility by an additional $100 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders.

In July 2005, we amended the credit agreement to increase the size of the revolving credit facility from $150 million to $300 million. We increased the one-time option under the revolving credit facility to expand the facility by an additional $150 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders. The amendment also updated certain debt covenant definitions. Other terms of the credit agreement remained unchanged.

Proceeds received from the March 2005 public offering of our common units were used to repay the $110 million term loan and a portion of the amount outstanding under the revolving credit facility. The term loan cannot be re-borrowed.

The interest rate under the credit agreement will fluctuate based on our ratio of total indebtedness to EBITDA. At our option, interest shall be payable at a base rate plus an applicable margin ranging up to 1.00 percent or at a rate derived from the London Interbank Offering Rate plus an applicable margin ranging from 1.00 percent to 2.00 percent.

In conjunction with the closing of the Cantera Acquisition, Penn Virginia Operating Co., LLC, also amended its $88 million Notes to allow us to enter the natural gas midstream business and to increase certain covenant coverage ratios, including the debt to EBITDA test. In exchange for this amendment, we agreed to a 0.25 percent increase in the fixed interest rate on the Notes, from 5.77 percent to 6.02 percent. The amendment to the Notes also requires that we obtain an annual confirmation of our credit rating, with a 1.00 percent increase in the interest rate payable on the Notes in the event our credit rating falls below investment grade. On March 15, 2005, our investment grade credit rating was confirmed by Dominion Bond Rating Services.

Interest Rate Swap. In March 2003, we entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of the Notes. The notional amount decreased by one-third of each principal payment. Under the terms of the interest rate swap agreement, the counterparty paid a fixed rate of 5.77 percent on the notional amount and received a variable rate equal to the floating interest rate which was determined semi-annually and was based on the six month London Interbank Offering Rate plus 2.36 percent. Settlements on the swap were recorded as interest expense. In conjunction with the closing of the Cantera Acquisition on March 3, 2005, we entered into an amendment to the Notes in which we agreed to a 0.25 percent increase in the fixed interest rate on the Notes, from 5.77 percent to 6.02 percent. This swap was designated as a fair value hedge because it had been determined that it was highly effective.

The interest rate swap agreement was settled on June 30, 2005, for $0.8 million paid. The settlement was paid in cash by us to the counterparty in July 2005. Upon settlement of the interest rate swap agreement, the $0.8 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the Notes using the interest rate method.

Future Capital Needs and Commitments. For the remainder of 2005, we anticipate making additional capital expenditures, excluding acquisitions, of approximately $15 million, primarily for construction of a processing plant and high speed rail loading facility on the Wayland property acquired in July 2005 and for system expansion and enhancement projects in our midstream segment. Part of our strategy is to make acquisitions which increase cash available for distribution to our unitholders. 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.

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. 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 complete future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating at the time.

Environmental

Surface Mining Valley Fills. Over the course of the last several years, opponents of surface mining have filed three lawsuits challenging the legality of permits authorizing the construction of valley fills for the disposal of coal mining overburden under federal and state laws applicable to surface mining activities. Although two of these challenges were successful in the United States District Court for the Southern District of West Virginia (the "District Court"), the United States Court of Appeals for the Fourth Circuit overturned both of those decisions in Bragg v. Robertson in 2001 and in Kentuckians For The Commonwealth v. Rivenburgh in 2003.

A ruling on July 8, 2004, which was made by the District Court in connection with a third lawsuit, may impair our lessees' ability to obtain permits that are needed to conduct surface mining operations. In this case, Ohio Valley Environmental Coalition v. Bulen, the District Court determined that the Army Corps of Engineers (the "Corps") violated the Federal Water Pollution Control Act of 1972, also known as the "Clean Water Act," and other federal statutes when it issued Nationwide Permit 21. This ruling is currently on appeal, but no decision has been issued by the appeals court as of yet.

In January of 2005, Kentucky Riverkeepers, Inc. and several other groups filed suit in federal district court in Kentucky challenging the legality of Nationwide Permit 21 and seeking to enjoin the Corps from issuing any general permits thereunder for fills associated with coal mining in Kentucky. Should the district court hearing this case follow the reasoning of Ohio Valley Environmental Coalition v. Bulen and similarly enjoin the Corps from issuing general permits for coal mining under that general permit, companies seeking permits under Section 404 of the Clean Water Act in Kentucky may have to file for individual permits that may result in increases in coal mining costs. We do not expect that our lessees would be affected significantly by the outcome in this case.

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.

Environmental Compliance. The operations of our lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of 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 agreed to indemnify us against any and all future environmental liabilities. We regularly visit coal properties under lease to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that our lessees will be able to comply with existing regulations and does not expect any material impact on our financial condition or results of operations.

We have certain reclamation bonding requirements with respect to certain of our unleased and inactive coal properties. As of June 30, 2005 and 2004, our environmental liabilities for coal properties totaled $1.4 million and $1.6 million, respectively. Given the uncertainty of when the reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Clean Air Act. Our midstream operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations govern emissions of pollutants into the air resulting from our activities, such as the activities of our processing plants and compressor stations, and also impose procedural requirements on how we conduct our 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. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

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

CERCLA. Our midstream operations could incur liability under the Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA and also known as Super Fund, and comparable state laws, regardless of our fault, in connection with the disposal or other release of hazardous substances or wastes, including those arising out of historical operations conducted prior to the Cantera Acquisition by Cantera, Cantera's predecessors or third parties on properties formerly owned by Cantera. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of "hazardous substance," in the course of its ordinary operations Cantera has generated, and we will generate, wastes that may fall within the definition of a "hazardous substance." CERCLA authorizes the United States Environmental Protection Agency 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. If we were to incur liability under CERCLA, we could be subject to joint and several liability for the costs of cleaning up hazardous substances, for damages to natural resources and for the costs of certain health studies.

We currently own or lease, and Cantera has in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although Cantera 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 the properties owned or leased by Cantera or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under Cantera's control. 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 remediations underway at several sites, but we do not believe that the associated costs will have a material impact on our operations.

Clean Water Act. Our operations can result in discharges of pollutants to waters. The Clean Water Act and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters or waters of the United States. 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. 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. We are subject to the requirements of the Occupational Safety and Health Act, referred to as 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.

Recent Accounting Pronouncements

See Note 13 in the Notes to Consolidated Financial Statements for a description of recent accounting pronouncements.

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

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

As of June 30, 2005, $86.2 million of our outstanding indebtedness carried a fixed interest rate throughout its term. We executed an interest rate derivative transaction in March 2003 to effectively convert the interest rate on one-third of the amount financed from a fixed rate of 5.77 percent to a floating rate of LIBOR plus 2.36 percent. The interest rate swap was accounted for as a fair value hedge in compliance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended by SFAS No. 137 and SFAS No. 138. The interest rate swap was settled on June 30, 2005, for $0.8 million. The settlement was paid in cash by us to the counterparty in July 2005.

When we agreed to acquire Cantera, we wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in a significant change in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a $13.9 million non-cash charge to earnings for the unrealized loss on derivatives. Subsequent to the Cantera Acquisition, we formally designated the agreements as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Upon qualifying for hedge accounting, changes in the derivative agreements' market value are accounted for as other comprehensive income or loss to the extent they are effective, rather than as a direct impact on net income. SFAS No. 133 requires us to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and we will be required to record the ineffective portion of the agreements in our net income for the respective period. Cash settlements with the counterparties related to the derivative agreements will occur monthly over the life of the agreements, with PVR receiving a correspondingly higher or lower amount for the physical sale of the commodity over the same period. Several derivative agreements for ethane, propane, crude oil and natural gas entered into subsequent to the Cantera Acquisition have been designated as cash flow hedges. See Note 5 of the Notes to Consolidated Financial Statements for a description of our hedging program and a listing of open derivative agreements and their fair value.

Forward-Looking Statements

Statements included in this report which are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions related thereto) are forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements which are also forward-looking statements. These statements use forward-looking words such as "may," "will," "anticipate," "believe," "expect," "project" or other similar words. These statements discuss goals, intentions and expectations as to future trends, plans, events, results of operations or financial condition or state other "forward looking" information.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, we caution you that assumed facts or bases almost always vary from actual results, and the differences between assumed facts or bases and actual results can be material, depending on the circumstances. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report and the documents we have incorporated by reference. These statements reflect our current views with respect to future events and are subject to various risks, uncertainties and assumptions including, but 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;
- the exposure we have 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 risk factors as detailed in the our Annual Report on Form 10-K for the year ended December 31, 2004.

Many of such factors are beyond our ability to control or predict. Readers are cautioned not to put undue reliance on forward-looking statements.

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

Item 4. Controls and Procedures

(a) Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to the Partnership and its consolidated subsidiaries is made known to the officers who certify the Partnership's financial reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. In addition, since the Partnership acquired its natural gas midstream business on March 3, 2005, our ability to effectively apply our disclosure controls and procedures to the acquired business is inherently limited by the short period of time we have had to evaluate those midstream operations since the acquisition.

The Partnership, under the supervision and with the participation of its management, including its principal executive officer and principal financial officer, performed an evaluation of the design and operation of the Partnership's disclosure controls and procedures (as defined in Securities and Exchange Act Rule 13a-15(e)) as of the end of the period covered by this report. Based on that evaluation, the Partnership's principal executive officer and principal financial officer concluded that such disclosure controls and procedures are effective to ensure that material information relating to the Partnership, including its consolidated subsidiaries, was accumulated and communicated to the Partnership's management and made known to the principal executive officer and principal financial officer, during the period for which this periodic report was being prepared.

(b) Changes in Internal Control over Financial Reporting

No changes were made in the Partnership's 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, except that we are in the process of evaluating the controls in the newly acquired natural gas midstream business and integrating the segment 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

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

12 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.

Date:	August 4, 2005	By:	/s/ Frank A. Pici Frank A. Pici, Vice President and Chief Financial Officer
Date:	August 4, 2005	By:	/s/ Forrest W. McNair Forrest W. McNair, Vice President and Controller

Penn Virginia Resource Partners, L.P.
Statement of Computation of Ratio of Earnings to Fixed Charges Calculation
(in thousands, except ratios)

	Year Ended December 31, 2000	January 1, 2001 through October 30, 2001	October 30, 2001 through December 31, 2001	2002	2003	2004	Six Months Ended June 30, 2005
Earnings							
Pre-tax income	$ 16,842	$ 19,113	$ 3,677	$ 24,686	$ 22,690	$ 34,315	$ 14,394
Equity earnings	-	-	-	-		(396)	(544)
Distributed income of equity investee	-	-	-	-		957	-
Fixed charges	7,670	7,027	274	1,786	5,048	7,328	6,212
Total earnings	**$ 24,512**	**$ 26,140**	**$ 3,951**	**$ 26,472**	**$ 27,738**	**$ 42,204**	**$ 20,062**
Fixed charges							
Interest expense	$ -	$ -	$ 269	$ 1,758	$ 4,986	$ 7,267	$ 6,195
Interest expense - affiliate	7,670	7,003	-	-	-	-	-
Rental interest factor	29	24	5	28	62	61	17
Total fixed charges	**$ 7,699**	**$ 7,027**	**$ 274**	**$ 1,786**	**$ 5,048**	**$ 7,328**	**$ 6,212**
Ratio of earnings to fixed charges	**3.2 x**	**3.7 x**	**14.4 x**	**14.8 x**	**5.5 x**	**5.8 x**	**3.2 x**

Exhibit 31.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, A. James Dearlove, Chief Executive Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P. (the "Registrant"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: August 4, 2005

/s/ A. James Dearlove
A. James Dearlove
Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Frank A. Pici, Vice President and Chief Financial Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P. (the "Registrant"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant;

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: August 4, 2005

/s/ Frank A. Pici
Frank A. Pici
Vice President and Chief Financial Officer

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-Q for the period ended June 30, 2005, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. James Dearlove, Chief Executive Officer of the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

August 4, 2005	/s/ A. James Dearlove A. James Dearlove Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-Q for the period ended June 30, 2005, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Pici, Vice-President and Chief Financial Officer of the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

August 4, 2005

/s/ Frank A. Pici
Frank A. Pici
Vice President and Chief Financial Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.