

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2008

or

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

For the transition period from _____ to _____

Commission File Number: 1-16735

PENN VIRGINIA RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

23-3087517

(I.R.S. Employer Identification No.)

THREE RADNOR CORPORATE CENTER, SUITE 300
100 MATSONFORD ROAD
RADNOR, PA 19087

(Address of principal executive offices)

(Zip Code)

(610) 687-8900

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by a check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer

Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

As of November 5, 2008, 51,798,895 common 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.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME – unaudited
(in thousands, except per unit data)**

	<u>Three Months Ended</u> <u>September 30,</u>		<u>Nine Months Ended</u> <u>September 30,</u>	
	<u>2008</u>	<u>2007</u>	<u>2008</u>	<u>2007</u>
Revenues				
Natural gas midstream	\$ 241,282	\$ 100,370	\$ 601,127	\$ 310,095
Coal royalties	33,308	24,426	88,911	73,455
Coal services	1,815	1,955	5,518	5,648
Other	8,871	3,453	23,039	9,350
Total revenues	<u>285,276</u>	<u>130,204</u>	<u>718,595</u>	<u>398,548</u>
Expenses				
Cost of midstream gas purchased	211,262	76,192	513,778	251,000
Operating	9,041	5,224	24,553	16,235
Taxes other than income	969	666	3,017	2,112
General and administrative	7,078	5,706	20,339	17,108
Depreciation, depletion and amortization	16,903	10,645	41,322	30,600
Total expenses	<u>245,253</u>	<u>98,433</u>	<u>603,009</u>	<u>317,055</u>
Operating income	40,023	31,771	115,586	81,493
Other income (expense)				
Interest expense	(7,060)	(4,678)	(17,366)	(11,842)
Other	(4,153)	299	(3,233)	931
Derivatives	15,742	(10,730)	(6,424)	(20,927)
Net income	<u>\$ 44,552</u>	<u>\$ 16,662</u>	<u>\$ 88,563</u>	<u>\$ 49,655</u>
General partner's interest in net income	<u>\$ 6,309</u>	<u>\$ 3,385</u>	<u>\$ 15,505</u>	<u>\$ 8,819</u>
Limited partners' interest in net income	<u>\$ 38,243</u>	<u>\$ 13,277</u>	<u>\$ 73,058</u>	<u>\$ 40,836</u>
Basic and diluted net income per limited partner unit (see Note 7)	<u>\$ 0.60</u>	<u>\$ 0.29</u>	<u>\$ 1.45</u>	<u>\$ 0.89</u>
Weighted average number of units outstanding, basic and diluted	51,663	46,106	48,804	46,103

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

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

	<u>September 30,</u> <u>2008</u>	<u>December 31,</u> <u>2007</u>
Assets		
Current assets		
Cash and cash equivalents	\$ 10,706	\$ 19,530
Accounts receivable	92,976	78,888
Derivative assets	3,825	1,212
Other current assets	4,792	4,104
Total current assets	<u>112,299</u>	<u>103,734</u>
Property, plant and equipment	1,068,328	877,571
Accumulated depreciation, depletion and amortization	<u>(183,591)</u>	<u>(146,289)</u>
Net property, plant and equipment	<u>884,737</u>	<u>731,282</u>
Equity investments	78,634	25,640
Goodwill	31,768	7,718
Intangibles, net	94,623	28,938
Derivative assets	1,051	-
Other long-term assets	<u>35,970</u>	<u>33,967</u>
Total assets	<u>\$ 1,239,082</u>	<u>\$ 931,279</u>
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	\$ 67,392	\$ 65,483
Accrued liabilities	12,959	10,753
Current portion of long-term debt	-	12,561
Deferred income	3,231	2,958
Derivative liabilities	<u>16,988</u>	<u>41,733</u>
Total current liabilities	100,570	133,488
Deferred income	8,604	6,889
Other liabilities	22,334	19,158
Derivative liabilities	2,982	1,315
Long-term debt	558,100	399,153
Partners' capital	<u>546,492</u>	<u>371,276</u>
Total liabilities and partners' capital	<u>\$ 1,239,082</u>	<u>\$ 931,279</u>

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

PENN VIRGINIA RESOURCE PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – unaudited
(in thousands)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
Cash flows from operating activities				
Net income	\$ 44,552	\$ 16,662	\$ 88,563	\$ 49,655
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	16,903	10,645	41,322	30,600
Derivative contracts:				
Total derivative losses (gains)	(14,239)	12,034	10,552	24,359
Cash settlements of derivatives	(14,054)	(4,702)	(33,279)	(8,963)
Non-cash interest expense	1,175	164	1,543	494
Equity earnings, net of distributions received	(1,409)	(255)	(1,415)	(1,133)
Other	(986)	-	(1,607)	(198)
Changes in operating assets and liabilities	(10,502)	(5,528)	(10,912)	(8,478)
Net cash provided by operating activities	<u>21,440</u>	<u>29,020</u>	<u>94,767</u>	<u>86,336</u>
Cash flows from investing activities				
Acquisitions	(156,791)	(93,423)	(253,031)	(145,879)
Additions to property, plant and equipment	(16,062)	(10,781)	(54,902)	(29,655)
Other	982	-	1,657	197
Net cash used in investing activities	<u>(171,871)</u>	<u>(104,204)</u>	<u>(306,276)</u>	<u>(175,337)</u>
Cash flows from financing activities				
Distributions to partners	(29,841)	(22,873)	(80,199)	(65,853)
Proceeds from borrowings	242,000	107,000	366,800	169,000
Repayments of borrowings	(65,400)	(18,000)	(220,800)	(23,000)
Net proceeds from issuance of partners' capital	-	-	140,958	-
Other	(3,454)	-	(4,074)	860
Net cash provided by financing activities	<u>143,305</u>	<u>66,127</u>	<u>202,685</u>	<u>81,007</u>
Net decrease in cash and cash equivalents	(7,126)	(9,057)	(8,824)	(7,994)
Cash and cash equivalents – beginning of period	17,832	12,503	19,530	11,440
Cash and cash equivalents – end of period	<u>\$ 10,706</u>	<u>\$ 3,446</u>	<u>\$ 10,706</u>	<u>\$ 3,446</u>
Supplemental disclosure:				
Cash paid for interest	\$ 6,764	\$ 6,642	\$ 17,136	\$ 13,545
Noncash investing activities: (see Note 3)				
Issuance of PVR units for acquisition	\$ 15,171	\$ -	\$ 15,171	\$ -
PVG units given as consideration for acquisition	\$ 68,021	\$ -	\$ 68,021	\$ -
Other liabilities	\$ 4,673	\$ -	\$ 4,673	\$ -

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

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – unaudited
September 30, 2008

1. Organization

Penn Virginia Resource Partners, L.P. (the “Partnership,” “we,” “us” or “our”) is a publicly traded Delaware limited partnership formed by Penn Virginia Corporation (“Penn Virginia”) in 2001 that is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. We currently conduct operations in two business segments: (i) coal and natural resource management and (ii) natural gas midstream.

Our coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees.

Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. We own and operate natural gas midstream assets located in Oklahoma and Texas. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We also own a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

Our general partner is Penn Virginia Resource GP, LLC, which is a wholly owned subsidiary of Penn Virginia GP Holdings, L.P. (“PVG”), a publicly traded Delaware limited partnership. At September 30, 2008, Penn Virginia owned an approximately 77% limited partner interest in PVG, as well as the non-economic general partner interest in PVG. At September 30, 2008, PVG owned an approximately 37% limited partner interest in us as well as 100% of our general partner, which owns a 2% general partner interest in us.

2. Summary of Significant Accounting Policies

Our accounting policies are consistent with those described in our Annual Report on Form 10-K for the year ended December 31, 2007. Please refer to such Form 10-K for a further discussion of those policies.

Basis of Presentation

Our condensed consolidated financial statements include the accounts of the Partnership and all of our wholly owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. Our condensed consolidated 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 (“SEC”) regulations. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation of our condensed consolidated financial statements have been included. These financial statements should be read in conjunction with our condensed consolidated financial statements and footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2007. Operating results for the three and nine months ended September 30, 2008 are not necessarily indicative of the results that may be expected for the year ending December 31, 2008.

New Accounting Standards

In March 2008, the Emerging Issues Task Force (“EITF”) ratified EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships* (“EITF 07-4”), which states that incentive distribution rights (“IDRs”) in a typical master limited partnership are participating securities under Statement of Financial Accounting Standards (“SFAS”) No. 128, *Earnings Per Share*. According to EITF 07-4,

when current-period earnings exceed cash distributions and the IDR is embedded in the general partner interest, undistributed earnings should not be allocated to the general partner (including embedded IDRs) and limited partners. Under the current accounting guidance, when current-period earnings exceed cash distributions and the IDR is embedded in the general partner interest, undistributed earnings should be allocated to the general partner. For the three and nine months ended September 30, 2008 and 2007, current-period earnings did not exceed cash distributions. See Note 7 – Partners’ Capital and Distributions. EITF 07-4 will be effective for fiscal years beginning after December 15, 2008 and applied retrospectively to all periods presented. Early application is not permitted. EITF 07-4 will eliminate our need to adjust our earnings per unit calculation in periods where current period earnings exceed distributions.

In April 2008, the Financial Accounting Standards Board (“FASB”) issued Staff Position No. FAS 142-3, *Determination of the Useful Life of Intangible Assets* (“FSP FAS 142-3”), which amends SFAS No. 142, *Goodwill and Other Intangible Assets*. The pronouncement requires that companies estimating the useful life of a recognized intangible asset consider their historical experience in renewing or extending similar arrangements or, in the absence of historical experience, consider assumptions that market participants would use about renewal or extension. FSP FAS 142-3 is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. Effective January 1, 2009, we will prospectively apply FSP FAS 142-3 to all intangible assets purchased.

3. Acquisitions

Lone Star Gathering, L.P.

On July 17, 2008, we completed an acquisition of substantially all of the assets of Lone Star Gathering, L.P. (“Lone Star Acquisition”). Lone Star’s assets are located in the southern portion of the Fort Worth Basin of North Texas and include approximately 129 miles of gas gathering pipelines and approximately 240,000 acres dedicated by active producers. The Lone Star Acquisition expands the geographic scope of the natural gas midstream segment into the Barnett Shale play in the Fort Worth Basin.

We acquired this business for approximately \$164.3 million and a liability of \$4.7 million, which represents the fair value of a \$5.0 million guaranteed payment, plus contingent payments of \$30.0 million and \$25.0 million. Funding for the acquisition was provided by \$80.7 million of borrowings under our revolving credit facility (the “Revolver”), 2,009,995 PVG common units (which we purchased from two subsidiaries of Penn Virginia for \$61.8 million) and 542,610 of our newly issued common units.

The contingent payments will be triggered if revenues from certain assets located in a defined geographic area reach certain targets by or before June 30, 2013 and will be funded in cash or common units, at our election.

The Lone Star Acquisition has been accounted for using the purchase method of accounting in accordance with SFAS No. 141, *Business Combinations*. Under the purchase method of accounting, the total purchase price has been preliminarily allocated to the net tangible and intangible assets acquired from Lone Star based on their estimated fair values. The allocations of purchase consideration are subject to change pending further review of the fair value of the assets acquired and liabilities assumed and actual transaction costs. The purchase price allocation is preliminary due to our continual assessment of potentially assumed asset retirement obligations that we may incur and review of certain contracts. The purchase price allocation will be finalized for any potential assets or liabilities related to the assets acquired in the Lone Star Acquisition. The total purchase price was allocated to the assets purchased based upon preliminary fair values on the date of the Lone Star Acquisition as follows:

Cash consideration paid for Lone Star	\$ 81,091
Fair value of PVG common units given as consideration for Lone Star	68,021
Fair value of PVR common units issued and given as consideration for Lone Star	15,171
Payment guaranteed December 31, 2009	4,673
Total purchase price	<u>\$ 168,956</u>
Fair value of assets acquired:	
Property and equipment	\$ 88,596
Intangible assets	69,200
Goodwill	11,160
Fair value of assets acquired	<u>\$ 168,956</u>

The preliminary purchase price includes approximately \$11.2 million of goodwill, all of which has been allocated to the natural gas midstream segment. A significant factor that contributed to the recognition of goodwill includes the ability to acquire an established business on the western border of the expanding Barnett Shale play in the Fort Worth Basin. Under SFAS No. 141 and SFAS 142, *Goodwill and Other Intangible Assets*, goodwill recorded in connection with a business combination is not amortized, but is tested for impairment at least annually. Accordingly, the accompanying pro forma combined income statement does not include amortization of the goodwill recorded in the acquisition. The preliminary purchase price includes approximately \$69.2 million of intangible assets that are associated with assumed contracts and customer relationships. These intangible assets will be amortized over 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*. We estimate the useful lives of these intangible assets to be 20 years.

The following pro forma financial information reflects the consolidated results of our operations as if the Lone Star Acquisition had occurred on January 1 of the reported period. The pro forma information includes adjustments primarily for depreciation of acquired property and equipment, the amortization of intangible assets, interest expense for acquisition debt and the change in weighted average common units resulting from the issuance of 542,610 of our newly issued common units given as consideration in the Lone Star Acquisition. 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		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Revenues	\$ 285,580	\$ 130,616	\$ 722,161	\$ 399,469
Net income	\$ 43,480	\$ 11,137	\$ 75,914	\$ 33,157
Net income per limited partner unit, basic & diluted	\$ 0.59	\$ 0.17	\$ 1.23	\$ 0.55

Thunder Creek Gas Services, LLC

In April 2008, we acquired a 25% member interest in Thunder Creek Gas Services, LLC (“Thunder Creek”), a joint venture that gathers and transports coalbed methane in Wyoming’s Powder River Basin for \$51.6 million in cash, after customary closing adjustments. Funding for the acquisition was provided by borrowings under the Revolver. The entire member interest is recorded in equity investments on the condensed consolidated balance sheet. This investment includes \$37.3 million of fair value for the net assets acquired and \$14.3 million of fair value paid in excess of our portion of the underlying equity in the net assets acquired related to customer contracts and related customer relations. This excess is being amortized to equity earnings over the life of the underlying contracts. The earnings are recorded in other revenues on the condensed consolidated statements of income.

Based on our analysis of the fair value of this acquisition, we did not deem our acquisition of Thunder Creek to be a material business combination and therefore are not disclosing pro forma financial information in accordance with SFAS No. 141.

4. Unit Offering

In 2008, we issued to the public 5.15 million common units to the public representing limited partner interests in us and received \$138.0 million in net proceeds. We received total contributions of \$2.9 million from our general partner to maintain its 2% general partner interest. We used net proceeds to repay a portion of our borrowings under the Revolver.

5. Fair Value Measurement of Financial Instruments

We adopted SFAS No. 157, *Fair Value Measurements*, effective January 1, 2008, for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157* (“FSP SFAS 157-2”), delays the application of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities to fiscal years and interim periods beginning after November 15, 2008. Examples of nonfinancial assets for which this FASB Staff Position delays application of SFAS No. 157 include business combinations, impairment and initial recognition of asset retirement obligations. We are currently assessing the impact on the financial statements of adopting FSP SFAS 157-2 effective January 1, 2009.

SFAS No. 157 requires fair value measurements to be classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

The following table summarizes the valuation of our financial instruments by the above SFAS No. 157 categories as of September 30, 2008 (in thousands):

Description	Fair Value Measurements, September 30, 2008	Fair Value Measurement at September 30, 2008, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Interest rate swap liability - current	\$ (1,399)	\$ -	\$ (1,399)	\$ -
Interest rate swap liability - noncurrent	(1,960)	-	(1,960)	-
Commodity derivative assets - current	3,825	-	3,825	-
Commodity derivative assets - noncurrent	1,051	-	1,051	-
Commodity derivative liability - current	(15,589)	-	(15,589)	-
Commodity derivative liability - noncurrent	(1,022)	-	(1,022)	-
Total	\$ (15,094)	\$ -	\$ (15,094)	\$ -

See Note 6 – Derivative Instruments, for the effects of these instruments on our condensed consolidated statements of income.

We use the following methods and assumptions to estimate the fair values in the above table:

- Commodity derivative instruments: We determine the fair values of our commodity derivative agreements based on forward price quotes for the respective commodities. This is a level 2 input. We

- generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. The discount rates used in the discounted cash flow projections include a measure of nonperformance risk. See Note 6 – Derivative Instruments.
- Interest rate swaps: We have entered into interest rate swap agreements (the “Revolver Swaps”) to establish fixed rates on a portion of the outstanding borrowings under the Revolver. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. This is a level 2 input. The discount rates used in the discounted cash flow projections include a measure of nonperformance risk. See Note 6 – Derivative Instruments.

6. Derivative Instruments

Natural Gas Midstream Segment Commodity Derivatives

We utilize costless collars, three-way collars and swap derivative contracts to hedge against the variability in cash flows associated with forecasted natural gas midstream revenues and cost of midstream gas purchased. We also utilize swap derivative contracts to hedge against the variability in our “frac spread.” Our frac spread is the spread between the purchase price for the natural gas we purchase from producers and the sale price for the natural gas liquids, or NGLs, that we sell after processing. We hedge against the variability in our frac spread by entering into swap derivative contracts to sell NGLs forward at a predetermined swap price and to purchase an equivalent volume of natural gas forward on an MMBtu basis. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues or cost savings from favorable price movements.

The counterparty to a costless collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. The counterparty to a swap contract is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract.

A three-way option contract consists of a collar contract as described above plus a put option contract sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only. This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

We determine the fair values of our derivative agreements based on forward price quotes for the respective commodities as of September 30, 2008, the credit risk of our counterparties and our own credit risk. The following table sets forth our positions as of September 30, 2008 for commodities related to natural gas midstream revenues and cost of midstream gas purchased:

	Average Volume Per Day	Weighted Average Price	Weighted Average Price Collars			Fair Value (in thousands)
			Additional Put Option	Put	Call	
Frac Spread	(in MMBtu)	(per MMBtu)				
Fourth Quarter 2008	7,824	\$ 5.02				\$ (2,805)
Ethane Sale Swap	(in gallons)	(per gallon)				
Fourth Quarter 2008	34,440	\$ 0.4700				(706)
Propane Sale Swaps	(in gallons)	(per gallon)				
Fourth Quarter 2008	26,040	\$ 0.7175				(1,751)
Crude Oil Sale Swaps	(in barrels)	(per barrel)				
Fourth Quarter 2008	560	\$ 49.27				(2,611)
Natural Gasoline Collar	(in gallons)			(per gallon)		
Fourth Quarter 2008	6,300			\$ 1.4800	\$ 1.6465	(266)
Crude Oil Collar	(in barrels)			(per barrel)		
Fourth Quarter 2008	400			\$ 65.00	\$ 75.25	(936)
Natural Gas Sale Swaps	(in MMBtu)	(per MMBtu)				
Fourth Quarter 2008	4,000	\$ 6.97				219
Crude Oil Three-Way Collar	(in barrels)			(per barrel)		
First Quarter 2009 through Fourth Quarter 2009	1,000		\$ 70.00	\$ 90.00	\$ 119.25	(1,128)
Frac Spread Collar	(in MMBtu)			(per MMBtu)		
First Quarter 2009 through Fourth Quarter 2009	6,000			\$ 9.09	\$ 13.94	1,435
Settlements to be paid in subsequent period						(3,186)
Natural gas midstream segment commodity derivatives - net liability						\$ (11,735)

At September 30, 2008, we reported a (i) net derivative liability related to the natural gas midstream segment of \$11.7 million and (ii) loss in accumulated other comprehensive income (“AOCI”) of \$1.4 million related to derivatives in the natural gas midstream segment for which we discontinued hedge accounting in 2006. The \$1.4 million loss will be recorded in earnings through the end of 2008 as the hedged transactions settle. See the *Adoption of SFAS No. 161* section below for the impact of the natural gas midstream commodity derivatives on our condensed consolidated statements of income.

Interest Rate Swaps

We have entered into the Revolver Swaps to establish fixed rates on a portion of the outstanding borrowings under the Revolver. Until March 2010, the notional amounts of the Revolver Swaps total \$210.0 million, or approximately 38% of our total long-term debt outstanding as of September 30, 2008, with us paying a weighted average fixed rate of 4.23% on the notional amount, and the counterparties paying a variable rate equal to the three-month London Interbank Offered Rate (“LIBOR”). From March 2010 to December 2011, the notional amounts of the Revolver Swaps total \$150.0 million with us paying a weighted average fixed rate of 4.23% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. Certain of our Revolver Swaps are designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the transactions for the swaps that are designated as cash flow hedges are recorded each period in AOCI. We reported a (i) derivative liability of \$3.4 million at September 30, 2008 and (ii) loss in AOCI of \$2.0 million at September 30, 2008 related to the Revolver Swaps. In connection with periodic settlements, we recognized \$0.8 million and \$1.2 million in net hedging losses in interest expense for the three and nine months ended September 30, 2008.

Adoption of SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging*

Activities, an Amendment of FASB Statement No. 133, which amends and expands SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. We elected to adopt SFAS No. 161 early, effective June 30, 2008. SFAS No. 161 requires companies to disclose how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows.

The following table summarizes the effects of our derivative activities, as well as the location of the gains and losses, on our condensed consolidated statements of income for the three and nine months ended September 30, 2008 (in thousands):

	<u>Location of gain (loss) on derivatives recognized in income</u>	<u>Three Months Ended September 30, 2008</u>	<u>Nine Months Ended September 30, 2008</u>
Derivatives designated as hedging instruments under SFAS No. 133:			
Interest rate contracts	Interest expense	\$ (854)	\$ (1,213)
Decrease in net income resulting from derivatives designated as hedging instruments under SFAS No. 133		\$ (854)	\$ (1,213)
Derivatives not designated as hedging instruments under SFAS No. 133:			
Interest rate contracts	Derivatives	\$ (1,333)	\$ (1,333)
Commodity contracts (1)	Natural gas midstream revenues	(1,987)	(6,235)
Commodity contracts (1)	Cost of midstream gas purchased	484	2,107
Commodity contracts	Derivatives	17,075	(5,091)
Increase (decrease) in net income resulting from derivatives not designated as hedging instruments under SFAS No. 133		\$ 14,239	\$ (10,552)
Total increase (decrease) in net income resulting from derivatives		\$ 13,385	\$ (11,765)
Realized and unrealized derivative impact:			
Cash paid for commodity contract settlements	Derivatives	(14,054)	(33,279)
Cash paid for interest rate contract settlements	Interest expense	(854)	(1,213)
Unrealized derivative gain	(2)	28,293	22,727
Total increase (decrease) in net income resulting from derivatives		\$ 13,385	\$ (11,765)

(1) These amounts represent reclassifications from AOCI. Subsequent to the discontinuation of hedge accounting for commodity derivatives in 2006, amounts remaining in AOCI have been reclassified into earnings in the same period or periods during which the original hedge forecasted transaction affects earnings. The amount remaining in AOCI that will be reclassified to earnings in future periods is \$1.4 million.

(2) This activity represents unrealized gains in the natural gas midstream, cost of midstream gas purchased and derivatives lines on our condensed consolidated statements of income.

Cash paid for commodity derivatives is included on the Derivatives line on our condensed consolidated statement of income, and cash paid for interest rate swaps is included on the Interest expense line on our condensed consolidated statement of income.

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments on our condensed consolidated balance sheets as of September 30, 2008 (in thousands):

	<u>Balance Sheet Location</u>	<u>Derivative Assets</u>	<u>Derivative Liabilities</u>
		<u>Fair values as of September 30, 2008</u>	
Derivatives designated as hedging instruments under SFAS No. 133:			
Interest rate contracts	Derivative liabilities - current	\$ -	\$ 92
Interest rate contracts	Derivative liabilities - noncurrent	-	206
Total derivatives designated as hedging instruments under SFAS No. 133		<u>\$ -</u>	<u>\$ 298</u>
Derivatives not designated as hedging instruments under SFAS No. 133:			
Interest rate contracts	Derivative liabilities - current	\$ -	\$ 1,307
Interest rate contracts	Derivative liabilities - noncurrent	-	1,754
Commodity contracts	Derivative assets/liabilities - current	3,825	15,589
Commodity contracts	Derivative liabilities - noncurrent	1,051	1,022
Total derivatives not designated as hedging instruments under SFAS No. 133		<u>\$ 4,876</u>	<u>\$ 19,672</u>
Total fair values of derivative instruments		<u>\$ 4,876</u>	<u>\$ 19,970</u>

The following table summarizes the effect of the Revolver Swaps on our total interest expense for the three and nine months ended September 30, 2008 (in thousands):

<u>Source</u>	<u>Three Months Ended</u>	<u>Nine Months Ended</u>
	<u>September 30, 2008</u>	
Borrowings	\$ (6,206)	\$ (16,828)
Capitalized interest (1)	-	675
Interest rate swaps	(854)	(1,213)
Total interest expense	<u>\$ (7,060)</u>	<u>\$ (17,366)</u>

(1) Capitalized interest for the nine months ended September 30, 2008 was primarily related to the construction of our natural gas gathering facilities. We did not have any capitalized interest in the three months ended September 30, 2008.

The above derivative activity represents cash flow hedges. As of September 30, 2008, none of our derivative instruments were classified as fair value hedges or trading securities. In addition, as of September 30, 2008, none of our derivative instruments contained credit risk contingencies.

7. Partners' Capital and Distributions

As of September 30, 2008, partners' capital consisted of 51.8 million common units, representing a 98% limited partner interest and a 2% general partner interest. As of September 30, 2008, affiliates of Penn Virginia, in the aggregate, owned a 39% interest in us, consisting of 19.7 million common units and a 2% general partner interest.

Subordinated Units

Until May 22, 2007, we had Class B units, a separate class of subordinated units representing limited partner interests in us, which were issued to PVG in connection with PVG's initial public offering. On May 22, 2007, all of our Class B units automatically converted into common units on a one-for-one basis and no Class B units remain outstanding.

Net Income per Limited Partner Unit

EITF Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128* (“EITF 03-6”) addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. EITF 03-6 provides that in any accounting period where our net income exceeds our distribution for such period, we are required to present net income per limited partner unit as if all of the net income for the period was distributed, regardless of the pro forma nature of this allocation and whether that net income would actually be distributed during a particular period from an economic or practical perspective. In this instance, basic and diluted net income per limited partner unit is determined by dividing net income available to limited partners by the weighted average number of limited partner units outstanding during the period. To calculate net income available to limited partners, income is first allocated to our general partner based on the amount of incentive distributions to which it is entitled and the remainder is allocated between the limited partners and our general partner based on their percentage ownership interests in us.

We make cash distributions on the basis of cash available for distributions, not net income, in any given accounting period. In accounting periods where our net income does not exceed our distributions for such period, EITF 03-6 does not apply and basic and diluted net income per limited partner unit is determined by dividing net income by the weighted average number of limited partner units outstanding during the period.

The following table reconciles net income and weighted average limited partner units used in computing basic and diluted net income per limited partner unit:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
	(in thousands, except per		(in thousands, except per unit	
	unit data)		data)	
Net income	\$ 44,552	\$ 16,662	\$ 88,563	\$ 49,655
Less: General partner’s incentive distributions paid	(5,528)	(3,114)	(14,014)	(7,986)
Subtotal	39,024	13,548	74,549	41,669
General partner interest in net income	(781)	(271)	(1,491)	(833)
Limited partners’ interest in net income	38,243	13,277	73,058	40,836
Additional earnings allocation to general partner under EITF 03-6	(7,061)	-	(2,057)	-
Net income available to limited partners under EITF 03-6	<u>\$ 31,182</u>	<u>\$ 13,277</u>	<u>\$ 71,001</u>	<u>\$ 40,836</u>
Weighted average limited partner units, basic and diluted	51,663	46,106	48,804	46,103
Basic and diluted net income per limited partner unit	\$ 0.60	\$ 0.29	\$ 1.45	\$ 0.89

Cash Distributions

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

According to our partnership agreement, our general partner receives incremental incentive cash distributions if cash distributions exceed certain target thresholds as follows:

	<u>Unitholders</u>	<u>General Partner</u>
Quarterly cash distribution per unit:		
First target -- up to \$0.275 per unit	98%	2%
Second target -- above \$0.275 per unit up to \$0.325 per unit	85%	15%
Third target -- above \$0.325 per unit up to \$0.375 per unit	75%	25%
Thereafter -- above \$0.375 per unit	50%	50%

The following table reflects the allocation of total cash distributions paid by us during the three and nine months ended September 30, 2008 and 2007:

	<u>Three Months Ended</u> <u>September 30,</u>		<u>Nine Months Ended</u> <u>September 30,</u>	
	<u>2008</u>	<u>2007</u>	<u>2008</u>	<u>2007</u>
	<u>(in thousands, except per unit data)</u>		<u>(in thousands, except per unit data)</u>	
Limited partner units	\$ 23,827	\$ 19,364	\$ 64,862	\$ 56,710
General partner interest (2%)	486	395	1,323	1,157
Incentive distribution rights	5,528	3,114	14,014	7,986
Total cash distributions paid	<u>\$ 29,841</u>	<u>\$ 22,873</u>	<u>\$ 80,199</u>	<u>\$ 65,853</u>
Total cash distributions paid per unit	\$ 0.46	\$ 0.42	\$ 1.35	\$ 1.23

In February 2008, the board of directors of our general partner paid a quarterly distribution of \$0.44 per unit to our unitholders (\$1.76 per unit on an annualized basis). In May 2008, the board of directors of our general partner paid a \$0.45 per unit quarterly distribution to our unitholders (\$1.80 per unit on an annualized basis). In August 2008, the board of directors of our general partner paid a quarterly distribution of \$0.46 per unit to our unitholders (\$1.84 per unit on an annualized basis). In October 2008, the board of directors of our general partner declared a quarterly distribution of \$0.47 per unit (\$1.88 per unit on an annualized basis). The distribution will be paid on November 14, 2008 to unitholders of record at the close of business on November 6, 2008.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of our outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then current market price of the common units.

8. Senior Notes Repayment and Revolver Amendment

In July 2008, we paid an aggregate of \$63.3 million to the holders of our Senior Unsecured Notes due 2013 (the "Notes") to prepay 100% of the aggregate principal amount of the Notes as provided in the Note Purchase Agreements governing the Notes. This amount consisted of approximately \$58.4 million aggregate principal amount outstanding on the Notes, \$1.1 million in accrued and unpaid interest on the Notes through the prepayment date and \$3.8 million in make-whole amounts due in connection with the prepayment of the Notes. We repaid the Notes with borrowings under the Revolver.

In August 2008, we amended and restated the Revolver to increase our available borrowings under the Revolver from \$600.0 million to \$700.0 million and to make it a secured facility. The Revolver is secured by substantially all of our assets.

9. Related-Party Transactions

General and Administrative

Penn Virginia charges us for certain corporate administrative expenses which are allocable to us and our subsidiaries. When allocating general corporate expenses, consideration is given to property and equipment, payroll and general corporate overhead. Any direct costs are paid by us. Total corporate administrative expenses charged to us and our subsidiaries totaled \$1.5 million and \$1.4 million for the three months ended September 30, 2008 and 2007 and \$4.6 million and \$4.0 million for the nine months ended September 30, 2008 and 2007. These costs are reflected in general and administrative expenses in our condensed consolidated statements of income. At least annually, our management performs an analysis of general corporate expenses based on time allocations of shared employees and other pertinent factors. Based on this analysis, our management believes that the allocation methodologies used are reasonable.

Accounts Payable—Affiliate

Amounts payable to related parties totaled \$15.9 million and \$2.4 million as of September 30, 2008 and December 31, 2007. The increase in the balance in the nine months ended September 30, 2008 is due primarily to amounts due to a wholly owned subsidiary of Penn Virginia, Penn Virginia Oil & Gas, L.P. (“PVOG”), related to the natural gas gathering and processing agreement between PVR East Texas Gas Processing, LLC (“PVR East Texas”) and PVOG. See “– Gathering and Processing Revenues.” These balances are included in accounts payable on our condensed consolidated balance sheets.

Marketing Revenues

PVOG and Connect Energy Services, LLC (“Connect Energy”), our wholly owned subsidiary, are parties to a Master Services Agreement effective September 1, 2006. Pursuant to the Master Services Agreement, PVOG and Connect Energy have agreed that Connect Energy will market all of PVOG’s oil and gas production in Arkansas, Louisiana, Oklahoma and Texas for a fee equal to 1% of the net sales price (subject to specified limitations) received by PVOG for such production. The Master Services Agreement has a primary term of five years and automatically renews for additional one-year terms until terminated by either party. Under the Master Services Agreement, PVOG paid fees to Connect Energy of \$1.0 million and \$0.4 million for the three months ended September 30, 2008 and 2007 and \$2.5 million and \$1.4 million for the nine months ended September 30, 2008 and 2007. Marketing revenues are included in other revenues on our condensed consolidated statements of income.

Gathering and Processing Revenues

PVR East Texas and PVOG are parties to a natural gas gathering and processing agreement effective during the first quarter of 2008. PVR East Texas will gather and process the natural gas delivered by PVOG. Connect Energy will purchase the processed gas and plant products (NGLs) from PVOG and sell them to third parties. PVOG paid PVR East Texas \$0.7 million and \$1.4 million in the three and nine months ended September 30, 2008 for gathering and processing fees. These gathering and processing revenues are recorded in the natural gas midstream line on our condensed consolidated statements of income. Connect Energy purchased processed gas and plant products from PVOG for \$55.7 million and \$105.5 million in the three and nine months ended September 30, 2008.

Purchase of PVG Units

In July 2008, we acquired natural gas midstream assets in the Fort Worth Basin in North Texas. Part of the consideration given by us in this transaction was 2,009,995 PVG common units, which we purchased from two subsidiaries of Penn Virginia for \$61.8 million. See Note 3 – Acquisitions.

10. Unit-Based Compensation

We recognized a total of \$0.8 million and \$0.7 million for the three months ended September 30, 2008 and 2007 and \$2.4 million and \$1.8 million for the nine months ended September 30, 2008 and 2007 of compensation expense related to the granting of common units and deferred common units and the vesting of restricted units granted under

the long-term incentive plan. During the nine months ended September 30, 2008, our general partner granted 134,551 restricted units with a weighted average grant date fair value of \$26.87 per unit to employees of Penn Virginia and its affiliates. During the same period, 70,007 restricted units with a weighted average grant date fair value of \$27.27 per unit vested. The restricted units granted in 2008 vest over a three-year period, with one-third vesting in each year. We recognize compensation expense on a straight-line basis over the vesting period.

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. The following table sets forth the components of comprehensive income for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in thousands)		(in thousands)	
Net income	\$ 44,552	\$ 16,662	\$ 88,563	\$ 49,655
Unrealized holding losses on derivative activities	(1,835)	(917)	(2,660)	(346)
Reclassification adjustment for derivative activities	3,691	1,129	6,675	2,913
Comprehensive income	<u>\$ 46,408</u>	<u>\$ 16,874</u>	<u>\$ 92,578</u>	<u>\$ 52,222</u>

12. 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, our management believes that these claims will not have a material effect on our financial position, liquidity or operations.

Environmental Compliance

Our operations and those 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 on the relevant lessees for all environmental and reclamation liabilities arising under those laws and regulations. The lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit our coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Our management believes that our operations and those of our lessees comply with existing laws and regulations and does not expect any material impact on our financial condition or results of operations.

As of September 30, 2008 and December 31, 2007, our environmental liabilities included \$1.2 million and \$1.5 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural resource management and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Mine Health and Safety Laws

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

13. 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 decision-making group consists of our Chief Executive Officer and other senior officers. This group routinely reviews and makes operating and resource allocation decisions among our coal and natural resource management operations and our natural gas midstream operations. Accordingly, our reportable segments are as follows:

- Coal and Natural Resource Management—management and leasing of coal properties and subsequent collection of royalties; other land management activities such as selling standing timber; leasing of fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants; collection of oil and gas royalties; and coal transportation, or wheelage, fees.
- Natural Gas Midstream—natural gas processing, gathering and other related services.

The following tables present a summary of certain financial information relating to our segments as of and for the three and nine months ended September 30, 2008 and 2007:

	Coal and Natural Resource Management	Natural Gas Midstream (in thousands)	Consolidated
For the Three Months Ended September 30, 2008:			
Revenues	\$ 41,660	\$ 243,616	\$ 285,276
Cost of midstream gas purchased	-	211,262	211,262
Operating costs and expenses	6,571	10,517	17,088
Depreciation, depletion and amortization	8,794	8,109	16,903
Operating income	<u>\$ 26,295</u>	<u>\$ 13,728</u>	40,023
Interest expense			(7,060)
Other			(4,153)
Derivatives			15,742
Net income			<u>\$ 44,552</u>
Total assets	\$ 619,430	\$ 619,652	\$ 1,239,082
Equity investments (1)	\$ 25,459	\$ 53,175	\$ 78,634
Goodwill	\$ -	\$ 31,768	\$ 31,768
Additions to property and equipment and acquisitions	\$ 497	\$ 172,356	\$ 172,853
For the Three Months Ended September 30, 2007:			
Revenues	\$ 28,416	\$ 101,788	\$ 130,204
Cost of midstream gas purchased	-	76,192	76,192
Operating costs and expenses	4,871	6,725	11,596
Depreciation, depletion and amortization	5,833	4,812	10,645
Operating income	<u>\$ 17,712</u>	<u>\$ 14,059</u>	31,771
Interest expense			(4,678)
Other			299
Derivatives			(10,730)
Net income			<u>\$ 16,662</u>
Total assets	\$ 561,169	\$ 287,769	\$ 848,938
Equity investments	\$ 26,428	\$ 60	\$ 26,488
Goodwill	\$ -	\$ 7,718	\$ 7,718
Additions to property and equipment and acquisitions	\$ 93,449	\$ 10,755	\$ 104,204

(1) The increase in equity investments is due to our 25% member interest in Thunder Creek that we acquired in 2008 for \$51.6 million. See Note 3 – Acquisitions.

	Coal and Natural Resource Management	Natural Gas Midstream (in thousands)	Consolidated
For the Nine Months Ended September 30, 2008:			
Revenues	\$ 111,010	\$ 607,585	\$ 718,595
Cost of midstream gas purchased	-	513,778	513,778
Operating costs and expenses	20,417	27,492	47,909
Depreciation, depletion and amortization	22,733	18,589	41,322
Operating income	<u>\$ 67,860</u>	<u>\$ 47,726</u>	115,586
Interest expense			(17,366)
Other			(3,233)
Derivatives			(6,424)
Net income			<u>\$ 88,563</u>
Total assets	\$ 619,430	\$ 619,652	\$ 1,239,082
Equity investments (1)	\$ 25,459	\$ 53,175	\$ 78,634
Goodwill	\$ -	\$ 31,768	\$ 31,768
Additions to property and equipment and acquisitions	\$ 25,186	\$ 282,747	\$ 307,933
For the Nine Months Ended September 30, 2007:			
Revenues	\$ 85,310	\$ 313,238	\$ 398,548
Cost of midstream gas purchased	-	251,000	251,000
Operating costs and expenses	15,489	19,966	35,455
Depreciation, depletion and amortization	16,643	13,957	30,600
Operating income	<u>\$ 53,178</u>	<u>\$ 28,315</u>	81,493
Interest expense			(11,842)
Other			931
Derivatives			(20,927)
Net income			<u>\$ 49,655</u>
Total assets	\$ 561,169	\$ 287,769	\$ 848,938
Equity investments	\$ 26,428	\$ 60	\$ 26,488
Goodwill	\$ -	\$ 7,718	\$ 7,718
Additions to property and equipment and acquisitions	\$ 146,915	\$ 28,619	\$ 175,534

(1) The increase in equity investments is due to our 25% member interest in Thunder Creek that we acquired in 2008 for \$51.6 million. See Note 3 – Acquisitions.

Item 2 Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of the financial condition and results of operations of Penn Virginia Resource Partners, L.P. and its subsidiaries (the "Partnership," "we," "us" or "our") should be read in conjunction with our condensed consolidated financial statements and the accompanying notes in Item 1, "Financial Statements."

Overview of Business

We are a publicly traded Delaware limited partnership formed by Penn Virginia in 2001 that is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. Both in our current limited partnership form and in our previous corporate form, we have managed coal properties since 1882. We currently conduct operations in two business segments: (i) coal and natural resource management and (ii) natural gas midstream. Our operating income was \$115.6 million for the nine months ended September 30, 2008, compared to \$81.5 million for the nine months ended September 30, 2007. In the nine months ended September 30, 2008, our coal and natural resource management segment contributed \$67.9 million, or 59%, to operating income, and our natural gas midstream segment contributed \$47.7 million, or 41%, to operating income.

The following table presents a summary of certain financial information relating to our segments for the nine months ended September 30, 2008 and 2007:

	<u>Coal and Natural Resource Management</u>	<u>Natural Gas Midstream</u>	<u>Consolidated</u>
		(in thousands)	
For the Nine Months Ended September 30, 2008:			
Revenues	\$ 111,010	\$ 607,585	\$ 718,595
Cost of midstream gas purchased	-	513,778	513,778
Operating costs and expenses	20,417	27,492	47,909
Depreciation, depletion and amortization	22,733	18,589	41,322
Operating income	<u>\$ 67,860</u>	<u>\$ 47,726</u>	<u>\$ 115,586</u>
For the Nine Months Ended September 30, 2007:			
Revenues	\$ 85,310	\$ 313,238	\$ 398,548
Cost of midstream gas purchased	-	251,000	251,000
Operating costs and expenses	15,489	19,966	35,455
Depreciation, depletion and amortization	16,643	13,957	30,600
Operating income	<u>\$ 53,178</u>	<u>\$ 28,315</u>	<u>\$ 81,493</u>

Since our inception as a publicly traded partnership, we have grown principally by making acquisitions in both of our business segments and, to a lesser extent, by organic growth on our properties. Readily available access to debt and equity capital and credit availability have been and continue to be critical factors in our ability to grow. The current deterioration in global financial markets and the consequential adverse effect on credit availability is adversely impacting our access to new capital and credit availability. Depending on the longevity and ultimate severity of this deterioration, our ability to make acquisitions may be significantly adversely affected, as may our ability to make cash distributions to our limited partners and to PVG, the owner of our general partner. See Part II, Item 1A – Risk Factors in this Quarterly Report on Form 10-Q.

Coal and Natural Resource Management Segment

As of December 31, 2007, we owned or controlled 818 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. 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 actively work with our lessees to develop efficient methods to exploit our reserves and to maximize production from our properties. We do not operate any mines. In the nine months ended September 30, 2008, our lessees produced 25.0 million tons of coal from our properties and paid us coal royalties revenues of \$88.9 million, for an average royalty per ton of \$3.56. Approximately 85% of our coal royalties revenues in the nine months ended September 30, 2008 were derived from coal mined on our properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of our coal royalties revenues for the respective periods was derived from coal mined on our properties under leases containing fixed royalty rates that escalate annually.

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. New legislation or regulations have been or may be adopted which may have a significant impact on the mining operations of our lessees or their customers' ability to use coal and which may require us, our lessees or our lessees' customers to change operations significantly or incur substantial costs.

To a lesser extent, coal prices also impact coal royalties revenues. Generally, as coal prices change, our average royalty per ton also changes because the majority of our lessees pay royalties based on the gross sales prices of the coal mined. Most of our coal is sold by our lessees under contracts with a duration of one year or more; therefore, changes to our average royalty occur as our lessees' contracts are renegotiated.

The future impact of the current deterioration of the global financial and credit markets on coal production levels and prices is uncertain. Depending on the longevity and ultimate severity of the deterioration, demand for coal may decline, which could adversely effect production and pricing for coal mined by our lessees, and, consequently, adversely effect the royalty income received by us and our ability to make cash distributions. See Part II, Item 1A – Risk Factors in this Quarterly Report on Form 10-Q.

We also earn revenue from the provision of fee-based coal preparation and loading services, from the sale of standing timber on our properties, from oil and gas royalty interests we own and from coal transportation, or wheelage, fees.

Natural Gas Midstream Segment

We own and operate natural gas midstream assets located in Oklahoma and Texas. These assets included approximately 4,059 miles of natural gas gathering pipelines as of September 30, 2008. We also owned five natural gas processing facilities having 300 MMcfd of total capacity as of September 30, 2008. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. We also own a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. In addition, we own a 25% member interest in Thunder Creek Gas Services, LLC ("Thunder Creek"), a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin.

For the nine months ended September 30, 2008, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 68.9 Bcf, or approximately 252 MMcfd. For the nine months ended September 30, 2008, two of our natural gas midstream customers accounted for 38% of our natural gas midstream segment revenues and 32% of our total consolidated revenues.

Revenues, profitability and the future rate of growth of our 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.

We continually seek new supplies of natural gas to offset the natural declines in production from the wells currently connected to our systems and to increase system throughput volumes. 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 contracting for natural gas that has been released from competitors' systems.

The current deterioration in global financial and credit markets will likely result in a decrease in worldwide demand for oil and domestic demand for natural gas and NGLs. Depending on the longevity and ultimate severity of the deterioration, NGL production from our processing plants could decrease and adversely effect our natural gas midstream processing income and our ability make cash distributions. See Part II, Item 1A – Risk Factors in this Quarterly Report on Form 10-Q.

Liquidity and Capital Resources

On an ongoing basis, we satisfy our working capital requirements and fund our capital expenditures, debt service obligations and distributions to unitholders using cash generated from our operations, borrowings under our revolving credit facility (the “Revolver”) and proceeds from equity offerings. We believe that the cash generated from our operations and our borrowing capacity will be sufficient to meet our working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and distribution payments. Our ability to satisfy our obligations and planned expenditures will depend on our future operating performance, which will be affected by, among other things, prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond our control. In addition, depending on the longevity and ultimate severity of the current deterioration of the global financial and credit markets, our ability to grow may be significantly adversely effected. Depending on the longevity and ultimate severity of this deterioration, our ability to make acquisitions may be significantly adversely affected, as may our ability to make cash distributions to our limited partners and to PVG, the owner of our general partner. See Part II, Item 1A – Risk Factors in this Quarterly Report on Form 10-Q.

Cash Flows

The following table summarizes our cash flow statements for the nine months ended September 30, 2008 and 2007 (in thousands):

For the Nine Months Ended September 30, 2008	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
Cash flows from operating activities:			
Net income contribution	\$ 44,987	\$ 43,576	\$ 88,563
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	24,025	(6,909)	17,116
Net change in operating assets and liabilities	16,852	(27,764)	(10,912)
Net cash provided by operating activities	<u>\$ 85,864</u>	<u>\$ 8,903</u>	<u>94,767</u>
Net cash used in investing activities	<u>\$ (23,478)</u>	<u>\$ (282,798)</u>	<u>(306,276)</u>
Net cash provided by financing activities			202,685
Net decrease in cash and cash equivalents			<u>\$ (8,824)</u>

For the Nine Months Ended September 30, 2007	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
Cash flows from operating activities:			
Net income contribution	\$ 41,615	\$ 8,040	\$ 49,655
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	15,806	29,353	45,159
Net change in operating assets and liabilities	631	(9,109)	(8,478)
Net cash provided by operating activities	<u>\$ 58,052</u>	<u>\$ 28,284</u>	<u>86,336</u>
Net cash used in investing activities	<u>\$ (146,718)</u>	<u>\$ (28,619)</u>	<u>(175,337)</u>
Net cash provided by financing activities			81,007
Net decrease in cash and cash equivalents			<u>\$ (7,994)</u>

Cash provided by operating activities increased by \$8.5 million, or 10%, from \$86.3 million in the nine months ended September 30, 2007 to \$94.8 million in the same period of 2008. This increase was primarily attributable to the increases in operating income in the coal and natural resource management and natural gas midstream segments, partially offset by increased cash paid for derivative settlements in the natural gas midstream segment.

Capital Expenditures

The following table sets forth capital expenditures by segment during the nine months ended September 30, 2008 and 2007:

	Nine Months Ended	
	September 30,	
	2008	2007
	(in thousands)	
Coal and natural resource management		
Acquisitions	\$ 25,014	\$ 145,878
Expansion capital	-	85
Other property and equipment	173	79
Total	<u>25,187</u>	<u>146,042</u>
Natural gas midstream		
Acquisitions (1)	254,132	-
Expansion capital	45,138	21,738
Other property and equipment	<u>10,824</u>	<u>7,370</u>
Total	<u>310,094</u>	<u>29,108</u>
Total capital expenditures	<u>\$ 335,281</u>	<u>\$ 175,150</u>

- (1) Natural gas midstream segment acquisitions in the nine months ended September 30, 2008 include newly issued PVR units valued at \$15.2 million; PVG units, which were purchased from PVA, valued at \$68.0 million; and a \$4.7 million guaranteed payment which will be paid in 2009. All of this was given as consideration in the acquisition of Lone Star Gathering, L.P. (the "Lone Star Acquisition"). See Note 3 – "Acquisitions" in the Notes to the Condensed Consolidated Financial Statements in Item 1, "Financial Statements."

In the nine months ended September 30, 2008, our natural gas midstream segment made aggregate capital expenditures of \$310.1 million, primarily related to our 25% member interest acquisition of Thunder Creek, the Lone Star Acquisition, pipeline assets in the Anadarko Basin of Oklahoma and Texas and expansion capital expenditures related to the Spearman Natural Gas Processing Plant in the Texas Panhandle ("Spearman plant") and Crossroads Natural Gas Processing Plant in East Texas ("Crossroads plant"). In the nine months ended September 30, 2008, our coal and natural resource management segment made aggregate capital expenditures of \$25.2 million, primarily to acquire approximately 29 million tons of coal reserves and an estimated 56 million board feet of hardwood timber in western Virginia and eastern Kentucky. In the nine months ended September 30, 2007, our natural gas midstream segment made aggregate capital expenditures of \$29.1 million, primarily for natural gas midstream system expansion projects and the acquisition of pipeline and compression facilities. In the nine months ended September 30, 2007, our coal and natural resource management segment made aggregate capital expenditures of \$146.0 million, primarily related to acquisitions of coal reserves, forestlands, a preparation plant and coal handling facilities.

We funded our coal and natural resource management and natural gas midstream capital expenditures in the nine months ended September 30, 2008 and 2007, primarily with cash provided by operating activities, borrowings under the Revolver and through the issuance of additional common units.

Distributions to partners increased to \$80.2 million in the nine months ended September 30, 2008 from \$65.9 million in the nine months ended September 30, 2007, because we increased the quarterly unit distribution from \$0.42 per unit to \$0.46 per unit.

We had net borrowings of \$146.0 million in the nine months ended September 30, 2008, comprised of net borrowings of \$210.4 million under the Revolver and net repayments of \$64.4 million under the Senior Unsecured Notes due 2013 (the "Notes"). We received net proceeds of \$140.9 million from the sale of our common units in a public offering in 2008, which was comprised of net proceeds of \$138.0 million from the sale of the common units to the public and \$2.9 million in contributions from our general partner to maintain its 2% general partner interest. These proceeds were mainly offset by total capital expenditures of \$335.3 million in the nine months ended September 30, 2008. This is compared to \$146.0 million of net borrowings in the nine months ended September 30,

2007, comprised of net borrowings of \$157.0 million under the Revolver and net repayments of \$11.0 million under the Notes. Funds from the borrowings in the nine months ended September 30, 2007 were primarily used for capital expenditures.

Long-Term Debt

Revolver. Net of outstanding borrowings and letters of credit, we had remaining borrowing capacity of \$140.3 million on the Revolver as of September 30, 2008. In August 2008, we increased the size of our Revolver from \$600 million to \$700.0 million and secured the Revolver with substantially all of our assets. The Revolver matures in December 2011 and is available to us for general purposes, including working capital, capital expenditures and acquisitions, and includes a \$10.0 million sublimit for the issuance of letters of credit. As of September 30, 2008, we had \$558.1 million of borrowings outstanding under the Revolver and we had outstanding letters of credit of \$1.6 million. In the nine months ended September 30, 2008, we incurred commitment fees of \$0.4 million on the unused portion of the Revolver. The interest rate under the Revolver fluctuates based on the ratio of our total indebtedness-to-EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if we select the base rate borrowing option under the Revolver or at a rate derived from the London Interbank Offered Rate (“LIBOR”), plus an applicable margin ranging from 0.75% to 1.75% if we select the LIBOR based borrowing option. The weighted average interest rate on borrowings outstanding under the Revolver in the nine months ended September 30, 2008 was 4.89%.

The financial covenants under the Revolver require us not to exceed specified ratios. We are required to maintain a debt-to-consolidated EBITDA ratio (the “Leverage Ratio”) of less than 5.25-to-1 and consolidated EBITDA-to-interest expense ratio of greater than 2.5-to-1 (the “Interest Coverage Ratio”). At September 30, 2008, our Leverage Ratio was 3.40-to-1.0 and our Interest Coverage Ratio was 5.44-to-1.0. The Revolver prohibits us from making distributions to our partners if any potential default, or event of default, as defined in the Revolver, occurs or would result from the distributions. In addition, the Revolver contains various covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of September 30, 2008, we were in compliance with all of our covenants under the Revolver.

Notes. In July 2008, we paid an aggregate of \$63.3 million to the holders of the Notes to prepay 100% of the aggregate principal amount of the Notes as provided in the Note Purchase Agreements governing the Notes. This amount consisted of approximately \$58.4 million aggregate principal amount outstanding on the Notes, \$1.1 million in accrued and unpaid interest on the Notes through the prepayment date and \$3.8 million in make-whole amounts due in connection with the prepayment of the Notes. The Notes were repaid with borrowings under the Revolver.

Interest Rate Swaps. We have entered into interest rate swap agreements (the “Revolver Swaps”) to establish fixed rates on a portion of the outstanding borrowings under the Revolver. Until March 2010, the notional amounts of the Revolver Swaps total \$210.0 million, or approximately 38% of our total long-term debt outstanding as of September 30, 2008, with us paying a weighted average fixed rate of 4.23% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From March 2010 to December 2011, the notional amounts of the Revolver Swaps total \$150.0 million, with us paying a weighted average fixed rate of 4.23% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. These swap agreements have been entered into with four financial institution counterparties, with no counterparty having more than 36% of the open positions. We are not aware of any specific concerns regarding our counterparties’ ability to make payments under any of the swap agreements. After considering the applicable margin of 1.75% in effect as of September 30, 2008, the total interest rate on the \$210.0 million portion of Revolver borrowings covered by the Revolver Swaps was 5.98% at September 30, 2008.

Unit Offering

In 2008, we issued 5.15 million common units to the public representing limited partner interests and received \$138.0 million in net proceeds. We received total contributions of \$2.9 million from our general partner in order to maintain its 2% general partner interest. The net proceeds were used to repay a portion of our borrowings under the Revolver.

Future Capital Needs and Commitments

Short-term cash requirements for operating expenses and quarterly distributions to our general partner and unitholders are expected to be funded through operating cash flows. For the remainder of 2008, we anticipate making capital expenditures of \$30.0 million to \$40.0 million, the majority of which will be incurred in the natural gas midstream segment. We intend to fund these capital expenditures with a combination of cash flows provided by operating activities and borrowings under the Revolver. 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 debt and equity securities.

Part of our long-term strategy is to make acquisitions and other capital expenditures which increase cash available for distribution to our unitholders. Our ability to make these acquisitions in the future will depend largely on the availability of debt financing and on our ability to periodically use equity financing through the issuance of new common units. Future financing will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating. The current disruption in the worldwide financial markets has made access to new debt and equity capital very difficult in the short term. If this situation continues for an extended period, our ability to issue debt and equity securities and to make acquisitions in the future may be limited, as will our ability to increase cash distributions to our limited partners and general partner.

Results of Operations

Selected Financial Data—Consolidated

The following table sets forth a summary of certain consolidated financial data for the three and nine months ended September 30, 2008 and 2007:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2008	2007	2008	2007
	(in thousands, except per unit data)			
Revenues	\$ 285,276	\$ 130,204	\$ 718,595	\$ 398,548
Expenses	\$ 245,253	\$ 98,433	\$ 603,009	\$ 317,055
Operating income	\$ 40,023	\$ 31,771	\$ 115,586	\$ 81,493
Net income	\$ 44,552	\$ 16,662	\$ 88,563	\$ 49,655
Net income per limited partner unit, basic and diluted	\$ 0.60	\$ 0.29	\$ 1.45	\$ 0.89
Cash flows provided by operating activities	\$ 21,440	\$ 29,020	\$ 94,767	\$ 86,336

Operating income increased by \$8.3 million in the three months ended September 30, 2008 compared to the same period of 2007 primarily due to the \$5.8 million increase in gross margin and the \$8.9 million increase in coal royalties revenue, partially offset by the \$3.8 million increase in operating expenses and the \$6.3 million increase in depreciation, depletion and amortization expenses (“DD&A”). Operating income increased by \$34.1 million in the nine months ended September 30, 2008 compared to the same period of 2007 primarily due to the \$28.3 million increase in gross margin and the \$15.5 million increase in coal royalties revenue, partially offset by \$8.3 million increase in operating expenses and the \$10.7 million increase in DD&A.

Net income increased by \$27.9 million in the three months ended September 30, 2008 compared to the same period in 2007 primarily due to the increase in operating income and a \$26.5 million change in derivatives. Net income increased by \$38.9 million in the nine months ended September 30, 2008 compared to the same period in 2007 primarily due to the increase in operating income and a \$14.5 million change in derivatives.

Coal and Natural Resource Management Segment

Three Months Ended September 30, 2008 Compared With the Three Months Ended September 30, 2007

The following table sets forth a summary of certain financial and other data for our coal and natural resource management segment and the percentage change for the three months ended September 30, 2008 and 2007:

	Three Months Ended September 30,		% Change
	2008	2007	
	(in thousands, except as noted)		
<u>Financial Highlights</u>			
Revenues			
Coal royalties	\$ 33,308	\$ 24,426	36%
Coal services	1,815	1,955	(7%)
Timber	1,911	113	1591%
Oil and gas royalty	1,940	264	635%
Other	2,686	1,658	62%
Total revenues	<u>41,660</u>	<u>28,416</u>	47%
Expenses			
Coal royalties expense	2,125	979	117%
Other operating	752	1,020	(26%)
Taxes other than income	373	242	54%
General and administrative	3,321	2,630	26%
Depreciation, depletion and amortization	8,794	5,833	51%
Total expenses	<u>15,365</u>	<u>10,704</u>	44%
Operating income	<u>\$ 26,295</u>	<u>\$ 17,712</u>	48%
<u>Operating Statistics</u>			
Royalty coal tons produced by lessees (tons in thousands)	8,496	8,842	(4%)
Average royalties revenues per ton (\$/ton)	\$ 3.92	\$ 2.76	42%
Less royalties expense per ton (\$/ton)	<u>(0.25)</u>	<u>(0.11)</u>	127%
Average net coal royalties per ton (\$/ton)	<u>\$ 3.67</u>	<u>\$ 2.65</u>	38%

Revenues. Coal royalties revenues increased by \$8.9 million, or 36%, from \$24.4 million in the three months ended September 30, 2007 to \$33.3 million in the same period of 2008. Coal royalties expense increased by \$1.1 million, or 117%, from \$1.0 million in the three months ended September 30, 2007 to \$2.1 million in the same period of 2008, primarily due to increases in production on subleased property. The average net coal royalty per ton, which represents the average coal royalties revenue per ton, net of coal royalties expense, increased by \$1.02 per ton, or 38%, from \$2.65 per ton in the three months ended September 30, 2007 to \$3.67 per ton in the same period of 2008. The increase in the average net coal royalty per ton was due primarily to the higher royalty revenues per ton received in Central Appalachia. The increase in royalty revenues per ton received in Central Appalachia was due primarily to the higher average sales price of coal in this region.

The following table summarizes coal production, coal royalties revenues and coal royalties per ton by region for the three months ended September 30, 2008 and 2007:

Property	Coal Production		Coal Royalties Revenues		Coal Royalties Per Ton	
	Three Months Ended		Three Months Ended		Three Months Ended	
	September 30,		September 30,		September 30,	
	2008	2007	2008	2007	2008	2007
	(tons in thousands)		(in thousands)		(\$/ton)	
Central Appalachia	4,815	4,660	\$ 25,184	\$ 16,799	\$ 5.23	\$ 3.60
Northern Appalachia	983	1,337	1,931	2,051	1.96	1.53
Illinois Basin	1,110	1,293	2,923	2,470	2.63	1.91
San Juan Basin	1,588	1,552	3,270	3,106	2.06	2.00
Total	8,496	8,842	\$ 33,308	\$ 24,426	\$ 3.92	\$ 2.76
Less coal royalties expense (1)			(2,125)	(979)	(0.25)	(0.11)
Net coal royalties revenues			\$ 31,183	\$ 23,447	\$ 3.67	\$ 2.65

(1) Our coal royalties expense is incurred primarily in the Central Appalachian region.

Coal production in Northern Appalachia decreased by 0.3 million tons, or 26%, from 1.3 million tons in the three months ended September 30, 2007 to 1.0 million tons in the same period of 2008. This decrease is primarily due to adverse longwall mining conditions. Coal production in the Illinois Basin decreased by 0.2 million tons, or 14%, from 1.3 million tons in the three months ended September 30, 2007 to 1.1 million tons in the same period of 2008. This decrease is primarily due to the closing of a mine in that region in 2008. Coal production in Central Appalachia and the San Juan Basin remained relatively constant from the three months ended September 30, 2007 to the same period of 2008.

Coal services revenues remained relatively constant in the three months ended September 30, 2007 to the same period of 2008. Timber revenues increased by \$1.8 million, or 1,591%, from \$0.1 million in the three months ended September 30, 2007 to \$1.9 million in the same period of 2008, due to the effects of the September 2007 forestland acquisition. Oil and gas royalty revenues increased by \$1.6 million, or 635%, from \$0.3 million in the three months ended September 30, 2007 to \$1.9 million in the same period of 2008, due to the increased royalties resulting from the October 2007 oil and gas royalty interest acquisition. Other revenues increased by \$1.0 million, or 62%, from \$1.7 million in the three months ended September 30, 2007 to \$2.7 million in the same period of 2008 primarily due to a \$0.8 million gain on the sale of coal reserves.

Expenses. Other operating expenses decreased by \$0.2 million, or 26%, from \$1.0 million in the three months ended September 30, 2007 to \$0.8 million in the same period of 2008, primarily due to decreased core-hole drilling. Taxes other than income remained relatively constant in the three months ended September 30, 2007 to the same period of 2008. General and administrative expenses increased by \$0.7 million, or 26%, from \$2.6 million in the three months ended September 30, 2007 to \$3.3 million in the same period of 2008, primarily due to increased staffing costs. DD&A expenses increased by \$3.0 million, or 51%, from \$5.8 million in the three months ended September 30, 2007 to \$8.8 million in the same period of 2008, primarily due to increased depletion resulting from the September 2007 forestland acquisition and the October 2007 oil and gas royalty interest acquisition.

Nine Months Ended September 30, 2008 Compared With the Nine Months Ended September 30, 2007

The following table sets forth a summary of certain financial and other data for our coal and natural resource management segment and the percentage change for the nine months ended September 30, 2008 and 2007:

	<u>Nine Months Ended September 30,</u>		<u>% Change</u>
	<u>2008</u>	<u>2007</u>	
	(in thousands, except as noted)		
<u>Financial Highlights</u>			
Revenues			
Coal royalties	\$ 88,911	\$ 73,455	21%
Coal services	5,518	5,648	(2%)
Timber	5,328	530	905%
Oil and gas royalty	4,730	847	458%
Other	6,523	4,830	35%
Total revenues	<u>111,010</u>	<u>85,310</u>	30%
Expenses			
Coal royalties expense	8,034	4,582	75%
Other operating	1,488	2,086	(29%)
Taxes other than income	1,115	832	34%
General and administrative	9,780	7,989	22%
Depreciation, depletion and amortization	22,733	16,643	37%
Total expenses	<u>43,150</u>	<u>32,132</u>	34%
Operating income	<u>\$ 67,860</u>	<u>\$ 53,178</u>	28%
<u>Operating Statistics</u>			
Royalty coal tons produced by lessees (tons in thousands)	24,975	25,186	(1%)
Average royalties revenues per ton (\$/ton)	\$ 3.56	\$ 2.92	22%
Less royalties expense per ton (\$/ton)	<u>(0.32)</u>	<u>(0.18)</u>	78%
Average net coal royalties per ton (\$/ton)	<u>\$ 3.24</u>	<u>\$ 2.74</u>	18%

Revenues. Coal royalties revenues increased by \$15.4 million, or 21%, from \$73.5 million in the nine months ended September 30, 2007 to \$88.9 million in the same period of 2008. Coal royalties expense increased by \$3.4 million, or 75%, from \$4.6 million in the nine months ended September 30, 2007 to \$8.0 million in the same period of 2008, due primarily to the increase in production on subleased property. The average net coal royalty per ton, which represents the average coal royalties revenue per ton, net of coal royalties expense, increased by \$0.50 per ton, or 18%, from \$2.74 per ton in the nine months ended September 30, 2007 to \$3.24 per ton in the same period of 2008. The increase in the average net coal royalty per ton was due primarily to the higher royalty revenues per ton received in Central Appalachia. The increase in royalty revenues per ton received in Central Appalachia was due primarily to higher average sales prices for coal in this region.

The following table summarizes coal production, coal royalties revenues and coal royalties per ton by region for the nine months ended September 30, 2008 and 2007:

Property	Coal Production		Coal Royalties Revenues		Coal Royalties Per Ton	
	Nine Months Ended		Nine Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,	
	2008	2007	2008	2007	2008	2007
	(tons in thousands)		(in thousands)		(\$/ton)	
Central Appalachia	14,770	14,635	\$ 68,213	\$ 53,983	\$ 4.62	\$ 3.69
Northern Appalachia	2,767	3,787	4,922	5,808	1.78	1.53
Illinois Basin	3,262	2,413	7,173	4,957	2.20	2.05
San Juan Basin	4,176	4,351	8,603	8,707	2.06	2.00
Total	24,975	25,186	\$ 88,911	\$ 73,455	\$ 3.56	\$ 2.92
Less coal royalties expense (1)			(8,034)	(4,582)	(0.32)	(0.18)
Net coal royalties revenues			\$ 80,877	\$ 68,873	\$ 3.24	\$ 2.74

(1) Our coal royalties expense is incurred primarily in the Central Appalachian region.

Coal production in Northern Appalachia decreased by 1.0 million tons, or 27%, from 3.8 million tons in the nine months ended September 30, 2007 to 2.8 million tons in the same period of 2008. This decrease was due primarily to adverse longwall mining conditions. Coal production in the Illinois Basin increased by 0.9 million tons, or 35%, from 2.4 million tons in the nine months ended September 30, 2007 to 3.3 million tons in the same period of 2008. This increase was due primarily to nine months of production in 2008 on the coal reserves that we acquired in June 2007. Coal production in Central Appalachia and in the San Juan Basin remained relatively constant from the nine months ended September 30, 2007 to the same period of 2008.

Coal services revenues remained relatively constant from the nine months ended September 30, 2007 to the same period of 2008. Timber revenues increased by \$4.8 million, or 905%, from \$0.5 million in the nine months ended September 30, 2007 to \$5.3 million in the same period of 2008 primarily due to the effects of the September 2007 forestland acquisition. Oil and gas royalty revenues increased by \$3.9 million, or 458%, from \$0.8 million in the nine months ended September 30, 2007 to \$4.7 million in the same period of 2008, primarily due to the increased royalties resulting from the October 2007 oil and gas royalty interest acquisition. Other revenues increased by \$1.7 million, or 35%, from \$4.8 million in the nine months ended September 30, 2007 to \$6.5 million in the same period of 2008, primarily due to increased wheelage attributable to better longwall production and increased coal sales prices compared to the same period of 2007 and a \$0.8 million gain on the sale of coal reserves.

Expenses. Other operating expenses decreased by \$0.6 million, or 29%, from \$2.1 million in the nine months ended September 30, 2007 to \$1.5 million in the same period of 2008, primarily due to a decrease in core-hole drilling. Taxes other than income increased by \$0.3 million, or 34%, from \$0.8 million in the nine months ended September 30, 2007 to \$1.1 million in the same period of 2008, primarily due to increased severance taxes resulting from the September 2007 forestland acquisition and the October 2007 oil and gas royalty interest acquisition. General and administrative expenses increased by \$1.8 million, or 22%, from \$8.0 million in the nine months ended September 30, 2007 to \$9.8 million in the same period of 2008, primarily due to increased staffing costs as well as increased accounting and auditing fees. DD&A expenses increased by \$6.1 million, or 37%, from \$16.6 million in the nine months ended September 30, 2007 to \$22.7 million in the same period of 2008 primarily due to increased depletion resulting from the September 2007 forestland acquisition and the October 2007 oil and gas royalty interest acquisition.

Natural Gas Midstream Segment

Three Months Ended September 30, 2008 Compared With the Three Months Ended September 30, 2007

The following table sets forth a summary of certain financial and other data for our natural gas midstream segment and the percentage change for the three months ended September 30, 2008 and 2007:

	Three Months Ended September 30,		% Change
	2008	2007	
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Residue gas	\$ 158,709	\$ 52,343	203%
Natural gas liquids	72,349	42,510	70%
Condensate	7,202	3,251	122%
Gathering, processing and transportation fees	3,022	2,266	33%
Total natural gas midstream revenues (1)	<u>241,282</u>	<u>100,370</u>	140%
Equity earnings in equity investment	981	-	-
Producer services	1,353	1,418	(5%)
Total revenues	<u>243,616</u>	<u>101,788</u>	139%
Expenses			
Cost of midstream gas purchased (1)	211,262	76,192	177%
Operating	6,164	3,225	91%
Taxes other than income	596	424	41%
General and administrative	3,757	3,076	22%
Depreciation and amortization	8,109	4,812	69%
Total operating expenses	<u>229,888</u>	<u>87,729</u>	162%
Operating income	<u>\$ 13,728</u>	<u>\$ 14,059</u>	(2%)
Operating Statistics			
System throughput volumes (MMcf)	27,744	17,844	55%
System throughput volumes (MMcfd)	302	194	56%
Gross margin	\$ 30,020	\$ 24,178	24%
Impact of derivatives	(12,551)	(3,398)	269%
Gross margin, adjusted for impact of derivatives	<u>\$ 17,469</u>	<u>\$ 20,780</u>	(16%)
Gross margin (\$/Mcf)	\$ 1.08	\$ 1.35	(20%)
Impact of derivatives (\$/Mcf)	(0.45)	(0.19)	137%
Gross margin, adjusted for impact of derivatives (\$/Mcf)	<u>\$ 0.63</u>	<u>\$ 1.16</u>	(46%)

(1) In the three months ended September 30, 2008, we recorded \$55.7 million of natural gas midstream revenue and \$55.7 million for the cost of midstream gas purchased related to the purchase of natural gas from Penn Virginia Oil & Gas, L.P. ("PVOG") and the subsequent sale of that gas to third parties. These transactions do not impact the gross margin.

Gross Margin. Our gross margin is the difference between our natural gas midstream revenues and our cost of midstream gas purchased. Natural gas midstream revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from system throughput volumes received, condensate collected and sold and gathering and other fees primarily from natural gas volumes connected to our gas processing plants. Cost of midstream gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

Natural gas midstream revenues increased by \$140.9 million, or 140%, from \$100.4 million in the three months ended September 30, 2007 to \$241.3 million in the same period of 2008. Cost of midstream gas purchased increased by \$135.1 million, or 177%, from \$76.2 million in the three months ended September 30, 2007 to \$211.3 million in the same period of 2008. The gross margin increased by \$5.8 million, or 24%, from \$24.2 million in the three months ended September 30, 2007 to \$30.0 million in the same period of 2008. The gross margin increase was a result of increased commodity pricing, increased system throughput volume and higher fractionation, or “frac” spreads during the three months ended September 30, 2008 compared to the same period of 2007. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMBtu basis.

System throughput volumes increased by 108 MMcf, or 56%, from 194 MMcf in the three months ended September 30, 2007 to 302 MMcf in the same period of 2008. This increase in throughput volumes is due primarily to the Crossroads plant in East Texas, which became fully operational in 2008, and to the Lone Star Acquisition, which we consummated in the third quarter of 2008. Also, the continued successful development by producers operating in the vicinity of our systems, as well as our success in contracting and connecting new supply contributed to the increase in throughput volume.

In 2008, our two expansion projects related to natural gas processing facilities were operational. These two natural gas processing facilities include the Spearman plant in the Texas Panhandle, which was placed into service in February 2008 and has approximately 60 MMcf capacity, and the Crossroads plant in East Texas, which was placed in service in April 2008 and has approximately 80 MMcf capacity. The Crossroads plant will process most of the Cotton Valley gas production for Penn Virginia, and the Spearman plant will process gas that had previously bypassed the Beaver plant.

During the three months ended September 30, 2008, we generated a majority of our gross margin from contractual arrangements under which the margin is exposed to increases and decreases in the price of natural gas and NGLs. As part of our risk management strategy, we use derivative financial instruments to economically hedge NGLs sold and natural gas purchased. Adjusted for the impact of derivative financial instruments, the gross margin decreased by \$3.3 million, or 16%, from \$20.8 million for the three months ended September 30, 2007 to \$17.5 million for the same period of 2008. On a per Mcf basis, the gross margin adjusted for the impact of derivatives decreased by \$0.53, or 46%, from \$1.16 per Mcf in the three months ended September 30, 2007 to \$0.63 per Mcf in the same period of 2008.

The following factors played a role in the decrease in gross margin adjusted for the impact of derivatives. At our Beaver/Spearman complex, which accounts for the majority of our system throughput volumes and processed natural gas, our gross margin decreased related to NGL production and transportation issues during the three months ended September 30, 2008. During this time, we experienced pipeline curtailments and fractionation facilities began allocating fractionation capacity, which forced us to store a portion of our NGL production. These curtailments and allocations occurred downstream and were not related to our facilities. Additionally, NGLs produced during the month of September were curtailed due to flooding and damage caused by Hurricane Ike. Many of the chemical plants on the Texas and Louisiana coast remained down during the weeks following the hurricane and were unable to take fractionated products. This resulted in the curtailment of NGLs by the fractionation facilities causing us to reduce our recoveries of NGLs from the natural gas stream. Both of these factors caused a corresponding decrease in gross margin. We expect all of the storage inventory at the end of the third quarter to be sold during the fourth quarter. In addition, the downstream fractionators and chemical plants are anticipated to continue their return to normal operations throughout the quarter. These factors as well as increased fee-based volumes associated with the Lone Star Acquisition and Crossroads plant contributed to the decrease in gross margin on a per Mcf basis.

Producer Services. Producer services revenues remained relatively constant from the three months ended September 30, 2007 to the same period of 2008.

Equity Earnings in Equity Investment. This increase is due to our 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming’s Powder River Basin. We acquired this member interest in April 2008.

Expenses. Total operating costs and expenses increased primarily due to increases in operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization.

Operating expenses increased by \$3.0 million, or 91%, from \$3.2 million in the three months ended September 30, 2007 to \$6.2 million in the same period of 2008, primarily due to expenses related to our acquisitions and expanding footprint in areas of operation, including the addition of the Spearman and Crossroads plants. These expenses include increased repairs and maintenance expenses, increased compressor rentals, chemical and treating expenses and increased employee expenses. Taxes other than income increased by \$0.2 million, or 41%, from \$0.4 million in the three months ended September 30, 2007 to \$0.6 million in the same period of 2008, primarily due to increased property taxes related to our acquisitions and expansion projects. General and administrative expenses increased by \$0.7 million, or 22%, from \$3.1 million in the three months ended September 30, 2007 to \$3.8 million in the same period of 2008, primarily due to increased staffing costs and accounting and auditing fees incurred. Depreciation and amortization expenses increased by \$3.3 million, or 69%, from \$4.8 million in the three months ended September 30, 2007 to \$8.1 million in the same period of 2008. This increase is primarily due to our acquisitions, which include the Lone Star Acquisition, and expansion capital incurred, which includes the Spearman and Crossroads plants.

Nine Months Ended September 30, 2008 Compared With the Nine Months Ended September 30, 2007

The following table sets forth a summary of certain financial and other data for our natural gas midstream segment and the percentage change for the nine months ended September 30, 2008 and 2007:

	<u>Nine Months Ended September 30,</u>		<u>% Change</u>
	<u>2008</u>	<u>2007</u>	
	(in thousands, except as noted)		
<u>Financial Highlights</u>			
Revenues			
Residue gas	\$ 373,913	\$ 181,407	106%
Natural gas liquids	199,053	115,660	72%
Condensate	21,870	9,324	135%
Gathering, processing and transportation fees	6,291	3,704	70%
Total natural gas midstream revenues (1)	<u>601,127</u>	<u>310,095</u>	94%
Equity earnings in equity investment	1,537	-	-
Producer services	4,921	3,143	57%
Total revenues	<u>607,585</u>	<u>313,238</u>	94%
Expenses			
Cost of midstream gas purchased (1)	513,778	251,000	105%
Operating	15,031	9,567	57%
Taxes other than income	1,902	1,280	49%
General and administrative	10,559	9,119	16%
Depreciation and amortization	18,589	13,957	33%
Total operating expenses	<u>559,859</u>	<u>284,923</u>	96%
Operating income	<u>\$ 47,726</u>	<u>\$ 28,315</u>	69%
<u>Operating Statistics</u>			
System throughput volumes (MMcf)	68,915	50,763	36%
System throughput volumes (MMcfd)	252	186	35%
Gross margin	\$ 87,349	\$ 59,095	48%
Impact of derivatives	(29,151)	(5,531)	427%
Gross margin, adjusted for impact of derivatives	<u>\$ 58,198</u>	<u>\$ 53,564</u>	9%
Gross margin (\$/Mcf)	\$ 1.27	\$ 1.16	9%
Impact of derivatives (\$/Mcf)	(0.42)	(0.11)	282%
Gross margin, adjusted for impact of derivatives (\$/Mcf)	<u>\$ 0.85</u>	<u>\$ 1.05</u>	(19%)

(1) In the nine months ended September 30, 2008, we recorded \$105.5 million of natural gas midstream revenue and \$105.5 million for the cost of midstream gas purchased related to the purchase of natural gas

from PVOG and the subsequent sale of that gas to third parties. These transactions do not impact the gross margin.

Gross Margin. Natural gas midstream revenues increased by \$291.0 million, or 94%, from \$310.1 million in the nine months ended September 30, 2007 to \$601.1 million in the same period of 2008. Cost of midstream gas purchased increased by \$262.8 million, or 105%, from \$251.0 million in the nine months ended September 30, 2007 to \$513.8 million in the same period of 2008. The gross margin increased by \$28.2 million, or 48%, from \$59.1 million in the nine months ended September 30, 2007 to \$87.3 million in the same period of 2008. The gross margin increase was a result of increased commodity pricing, increased system throughput volume production and higher fractionation, or “frac” spreads during the nine months ended September 30, 2008 compared to the same period of 2007. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMBtu basis.

System throughput volumes increased by 66 MMcfd, or 35%, from 186 MMcfd in the nine months ended September 30, 2007 to 252 MMcfd in the same period of 2008. This increase in throughput volumes is due primarily to the Crossroads plant in East Texas, which became fully operational in 2008, and to the Lone Star Acquisition, which we consummated in the third quarter of 2008. Also, the continued successful development by producers operating in the vicinity of our systems, as well as our success in contracting and connecting new supply contributed to the increase in throughput volume.

In 2008, our two expansion projects related to natural gas processing facilities were operational. These two natural gas processing facilities included the Spearman plant in the Texas Panhandle, which was placed into service in February 2008 and has approximately 60 MMcfd capacity and the Crossroads plant in East Texas, which was placed in service in April 2008 and has approximately 80 MMcfd capacity. The Crossroads plant will process most of the Cotton Valley gas production for Penn Virginia, and the Spearman plant will process gas that had previously bypassed the Beaver plant.

During the nine months ended September 30, 2008, we generated a majority of the gross margin from contractual arrangements under which the gross margin is exposed to increases and decreases in the price of natural gas and NGLs. As part of our risk management strategy, we use derivative financial instruments to economically hedge NGLs sold and natural gas purchased. Adjusted for the impact of derivative financial instruments, our gross margin increased by \$4.6 million, or 9%, from \$53.6 million for the nine months ended September 30, 2007 to \$58.2 million for the same period of 2008. On a per Mcf basis, the gross margin adjusted for the impact of derivatives decreased by \$0.20, or 19%, from \$1.05 per Mcf in the nine months ended September 30, 2007 to \$0.85 in the same period of 2008.

The following factors played a role in the decrease in gross margin adjusted for the impact of derivatives. At our Beaver/Spearman complex, which accounts for the majority of our system throughput volumes and processed natural gas, our gross margin decreased related to NGL production and transportation issues during the nine months ended September 30, 2008. During this time, we experienced pipeline curtailments and fractionation facilities began allocating fractionation capacity, which forced us to store a portion of our NGL production. These curtailments and allocations occurred downstream and were not related to our facilities. Additionally, NGLs produced during the month of September were curtailed due to flooding and damage caused by Hurricane Ike. Many of the chemical plants on the Texas and Louisiana coast remained down during the weeks following the hurricane and were unable to take fractionated products. This resulted in the curtailment of NGLs by the fractionation facilities causing us to reduce our recoveries of NGLs from the natural gas stream. Both of these factors caused a corresponding decrease in gross margin. We expect all of the storage inventory at the end of the third quarter to be sold during the fourth quarter. In addition, the downstream fractionators and chemical plants are anticipated to continue their return to normal operations throughout the quarter. These factors as well as increased fee-based volumes associated with the Lone Star Acquisition and Crossroads plant contributed to the decrease in gross margin on a per Mcf basis.

Producer Services. Producer services revenues increased by \$1.8 million, or 57%, from \$3.1 million in the nine months ended September 30, 2007 to \$4.9 million in the same period of 2008 primarily due to an increase in collected agent fees for the marketing of Penn Virginia’s and other third parties’ natural gas production.

Equity Earnings in Equity Investment. This increase is due to our 25% member interest in Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. We acquired this member interest in April 2008.

Expenses. Total operating costs and expenses increased primarily due to increases in operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization.

Operating expenses increased by \$5.4 million, or 57%, from \$9.6 million in the nine months ended September 30, 2007 to \$15.0 million in the same period of 2008, primarily due to expenses related to our expanding footprint in areas of operation, including acquisitions and the addition of the Spearman and Crossroads plants. These expenses include increased repairs and maintenance expenses, increased compressor rentals, chemical and treating expenses and increased employee expenses. Taxes other than income increased by \$0.6 million, or 49%, from \$1.3 million in the nine months ended September 30, 2007 to \$1.9 million in the same period of 2008, primarily due to increased property taxes resulting from our acquisitions and from the construction of the Spearman and Crossroads plants, and is also due to increased payroll taxes resulting from increased staffing. General and administrative expenses increased by \$1.5 million, or 16%, from \$9.1 million in the nine months ended September 30, 2007 to \$10.6 million in the same period of 2008 primarily due to increased staffing costs and accounting and auditing fees incurred. Depreciation and amortization expenses increased by \$4.6 million, or 33%, from \$14.0 million in the nine months ended September 30, 2007 to \$18.6 million in the same period of 2008. This increase is primarily due to our acquisitions, which include the Lone Star Acquisition, and expansion capital incurred, which includes the Spearman and Crossroads plants.

Other

Our other results consist of interest expense and derivative gains and losses.

Interest Expense. Our consolidated interest expense is comprised of the following:

Source	Three Months September 30,		%	Nine Months Ended September 30,		%
	2008	2007		2008	2007	
	(in thousands)			(in thousands)		
PVR borrowings	(6,206)	(4,852)		(16,828)	(12,360)	
PVR capitalized interest	-	-		675	-	
PVR interest rate swaps	(854)	174		(1,213)	518	
Total interest expense	<u>\$(7,060)</u>	<u>\$(4,678)</u>	51%	<u>\$ (17,366)</u>	<u>\$(11,842)</u>	47%

Interest expense increased by \$2.4 million, or 51%, from \$4.7 million in the three months ended September 30, 2007 to \$7.1 million in the same period of 2008. This increase is primarily due to the increase in our average debt balance, which increased from \$295.7 million for the three months ended September 30, 2007 to \$510.1 million for the same period of 2008. The increase in our average debt balance is due primarily to acquisitions and expansion activity. We had no capitalized interest in the three months ended September 30, 2008 and 2007. In connection with periodic settlements, we recognized \$0.9 million in net hedging losses on the Revolver Swaps in interest expense for the three months ended September 30, 2008.

Interest expense increased by \$5.6 million, or 47%, from \$11.8 million in the nine months ended September 30, 2007 to \$17.4 million in the same period of 2008. This increase is primarily due to the increase in our average debt balance, which increased from \$253.8 million for the nine months ended September 30, 2007 to \$454.3 million for the same period of 2008. The increase in our average debt balance is due primarily to acquisitions and expansion activity. We also capitalized \$0.7 million of interest costs in the nine months ended September 30, 2008 related to the construction of the Spearman and Crossroads plants. We had no capitalized interest in the nine months ended September 30, 2007. In connection with periodic settlements, we recognized \$1.2 million in net hedging losses on the Revolver Swaps in interest expense for the nine months ended September 30, 2008.

Derivatives. Our results of operations and operating cash flows were impacted by changes in market prices for NGLs, crude oil and natural gas prices. Commodity markets are volatile, and as a result, our hedging activity results can vary significantly. Our results of operations are affected by the volatility of changes in fair value, which fluctuate with changes in NGL, crude oil and natural gas prices.

In the three months ended September 30, 2008, derivative gains were \$15.7 million for changes in fair value. Cash paid for settlements totaled \$14.1 million for the three months ended September 30, 2008. The derivative expenses in the three months ended September 30, 2007 were \$10.7 million for changes in fair value. Cash paid for settlements totaled \$4.7 million for the three months ended September 30, 2007.

In the nine months ended September 30, 2008, derivative expenses were \$6.4 million for changes in fair value. Cash paid for settlements totaled \$33.3 million for the nine months ended September 30, 2008. The derivative expenses in the nine months ended September 30, 2007 were \$20.9 million for changes in fair value. Cash paid for settlements totaled \$9.0 million for the nine months ended September 30, 2007.

Our derivative activity is summarized below:

	Three Months Ended			Nine Months Ended		
	September 30,		%	September 30,		%
	2008	2007	Change	2008	2007	Change
	(in thousands)			(in thousands)		
Natural gas midstream segment unrealized derivative gain (loss)	29,796	(6,028)	(594%)	26,855	(11,964)	(324%)
Natural gas midstream segment realized loss	(14,054)	(4,702)	199%	(33,279)	(8,963)	271%
Total derivative gain (loss)	\$ 15,742	\$ (10,730)	(247%)	\$ (6,424)	\$ (20,927)	(69%)

Summary of Critical Accounting Policies and Estimates

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

Natural Gas Midstream Revenues

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

Coal Royalties Revenues

We recognize coal royalties revenues 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. We record any differences, which historically have not been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Derivative Activities

Until 2006, we used hedge accounting for commodity derivative financial instruments as allowed under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Our commodity derivative financial instruments initially qualified as cash flow hedges, and changes in fair value from these contracts were deferred in accumulated other comprehensive income until the hedged transactions settled. When we discontinued hedge accounting in 2006, a net loss remained in accumulated other comprehensive income. As the hedged transactions settled in 2006 and 2007, we recognized the deferred changes in fair value in revenues and cost of gas purchased in our condensed consolidated statements of income. As of September 30, 2008, we had \$1.4 million of net losses remaining in accumulated other comprehensive income. We will recognize these hedging losses during the remainder of 2008 as the hedged transactions settle.

Beginning in 2006, we began recognizing changes in fair value in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners' capital). Because we no longer use hedge accounting for our commodity derivatives, we have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of these contracts. Our results of operations are affected by the potential volatility of changes in fair value, which fluctuate with changes in NGL, crude oil and natural gas prices. These fluctuations could be significant in a volatile pricing environment.

Depletion

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by our own geologists and coal reserve engineers. Our estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. We deplete timber on an area-by-area basis at a rate based upon the quantity of timber sold. We determine depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves.

Equity Investments

We use the equity method of accounting to account for our 25% member interest in Thunder Creek, as well as our investment in a coal handling joint venture, recording the initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect our share of income of the investee and is reduced to reflect our share of losses of the investee or distributions received from the investee as the joint ventures reports them. Our share of earnings or losses from Thunder Creek is included in other revenues on the condensed consolidated statements of income, and our share of earnings and losses from the coal handling joint venture is included in coal services on the condensed consolidated statements of income. Other revenues and coal services revenues also include amortization of the amount of the equity investments that exceed our portion of the underlying equity in net assets. We record amortization over the life of the contracts acquired in the Thunder Creek acquisition and the life of the coal services contracts acquired in the acquisition of the coal handling joint venture.

Goodwill

Under SFAS No. 141, *Business Combinations*, and SFAS No. 142, goodwill recorded in connection with a business combination is not amortized, but tested for impairment at least annually. Accordingly, we do not amortize goodwill. We test goodwill for impairment during the fourth quarter of each fiscal year.

Intangible Assets

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 20 years, the period in which benefits are derived from the contracts, relationships and rights-of-way, and are reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

Fair Value Measurements

We adopted SFAS No. 157, *Fair Value Measurements*, effective January 1, 2008, for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157*, delays the application of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities to fiscal years and interim periods beginning after November 15, 2008.

SFAS No. 157 requires fair value measurements to be classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

We use the following methods and assumptions to estimate the fair values of financial instruments:

- Commodity derivative instruments: The fair values of our derivative agreements are determined based on forward price quotes for the respective commodities. This is a level 2 input. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. The discount rates used in the discounted cash flow projections include a measure of nonperformance risk. See Note 6 – “Derivative Instruments” in the Notes to the Condensed Consolidated Financial Statements in Item 1, “Financial Statements.”
- Interest rate swaps: We have entered into the Revolver Swaps to establish fixed rates on a portion of the outstanding borrowings under the Revolver. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. This is a level 2 input. The discount rates used in the discounted cash flow projections include a measure of nonperformance risk. See Note 6 – “Derivative Instruments” in the Notes to the Condensed Consolidated Financial Statements in Item 1, “Financial Statements.”

Environmental Matters

Our operations and those 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 on the relevant lessees for all environmental and reclamation liabilities arising under those laws and regulations. The lessees are bonded and have indemnified us against any and all future environmental liabilities. We regularly visit our coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. Our management believes that our operations and those of our lessees comply with existing laws and regulations and does not expect any material impact on our financial condition or results of operations.

As of September 30, 2008 and December 31, 2007, our environmental liabilities included \$1.2 million and \$1.5 million, which represents our best estimate of the liabilities as of those dates related to our coal and natural resource management and natural gas midstream businesses. We have reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Recent Accounting Pronouncements

See Note 2 – “Summary of Significant Accounting Policies,” in the Notes to the Condensed Consolidated Financial Statements in Item 1, “Financial Statements,” for a description of recent accounting pronouncements.

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- the volatility of commodity prices for natural gas, NGLs, crude oil and coal;
- the relationship between natural gas, NGL and coal prices;
- the projected demand for and supply of natural gas, NGLs and coal;
- competition among producers in the coal industry generally and among natural gas midstream companies;
- the extent to which the amount and quality of actual production of our coal differs from estimated recoverable coal reserves;
- our ability to generate sufficient cash from our businesses to maintain and pay the quarterly distribution to our general partner and our unitholders;
- the experience and financial condition of our coal lessees and natural gas midstream customers, including our lessees’ ability to satisfy their royalty, environmental, reclamation and other obligations to us and others;
- operating risks, including unanticipated geological problems, incidental to our coal and natural resource management or natural gas midstream business;
- our ability to acquire new coal reserves or natural gas midstream assets and new sources of natural gas supply and connections to third-party pipelines on satisfactory terms;
- our ability to retain existing or acquire new natural gas midstream customers and coal lessees;
- the ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves and obtain favorable contracts for such production;
- the occurrence of unusual weather or operating conditions including force majeure events;
- delays in anticipated start-up dates of our lessees’ mining operations and related coal infrastructure projects and new processing plants in our natural gas midstream business;
- environmental risks affecting the mining of coal reserves or the production, gathering and processing of natural gas;
- the timing of receipt of necessary governmental permits by us or our lessees;
- hedging results;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- uncertainties relating to the outcome of current and future litigation regarding mine permitting;
- risks and uncertainties relating to general domestic and international economic (including inflation, interest rates and financial and credit markets) and political conditions (including the impact of potential terrorist attacks); and

- other risks set forth in Item 1A, “Risk Factors,” of this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the SEC, including our Annual Report on Form 10-K for the year ended December 31, 2007. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management’s views only as of the date hereof. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise.

Item 3 *Quantitative and Qualitative Disclosures About Market Risk*

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

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

As a result of our price risk management and interest rate risk management activities as discussed below, we are also exposed to counterparty risk with financial institutions with whom we enter into these risk management positions. Sensitivity to these risks have heightened due to the recent disruption in the domestic and international credit markets. We did not believe we had significant risk in the financial stability of our counterparties at the time of this report.

Price Risk Management

Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to seek to mitigate the price risks associated with fluctuations in natural gas, NGL and crude oil prices as they relate to our natural gas midstream business. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair values of our price risk management activities are significantly affected by fluctuations in the prices of natural gas, NGLs and crude oil.

For the nine months ended September 30, 2008, we reported a net derivative expense of \$6.4 million. Until 2006, we used hedge accounting for commodity derivative financial instruments as allowed under SFAS No. 133. Our commodity derivative financial instruments initially qualified as cash flow hedges, and changes in fair value from these contracts were deferred in accumulated comprehensive income until the hedged transactions settled. When we discontinued hedge accounting in 2006, a net loss remained in accumulated other comprehensive income. As the hedged transactions settled in 2006 and 2007, we recognized the deferred changes in fair value in revenues and cost of gas purchased in our condensed consolidated statements of income. As of September 30, 2008, we had \$1.4 million of net losses remaining in accumulated other comprehensive income. We will recognize these hedging losses during the remainder of 2008 as the hedged transactions settle.

Beginning in 2006, we began recognizing changes in fair value in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (partners’ capital). Because we no longer use hedge accounting for our commodity derivatives, we have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of these contracts. Our results of operations are affected by the potential volatility of changes in fair value, which fluctuate with changes in natural gas, NGL and crude oil prices. These fluctuations could be significant in a volatile pricing environment.

The following table lists our derivative agreements and their fair values as of September 30, 2008:

	Average Volume Per Day	Weighted Average Price	Weighted Average Price Collars			Fair Value (in thousands)
			Additional Put Option	Put	Call	
Frac Spread	(in MMBtu)	(per MMBtu)				
Fourth Quarter 2008	7,824	\$ 5.02				\$ (2,805)
Ethane Sale Swap	(in gallons)	(per gallon)				
Fourth Quarter 2008	34,440	\$ 0.4700				(706)
Propane Sale Swaps	(in gallons)	(per gallon)				
Fourth Quarter 2008	26,040	\$ 0.7175				(1,751)
Crude Oil Sale Swaps	(in barrels)	(per barrel)				
Fourth Quarter 2008	560	\$ 49.27				(2,611)
Natural Gasoline Collar	(in gallons)			(per gallon)		
Fourth Quarter 2008	6,300			\$ 1.4800 \$ 1.6465		(266)
Crude Oil Collar	(in barrels)			(per barrel)		
Fourth Quarter 2008	400			\$ 65.00 \$ 75.25		(936)
Natural Gas Sale Swaps	(in MMBtu)	(per MMBtu)				
Fourth Quarter 2008	4,000	\$ 6.97				219
Crude Oil Three-Way Collar	(in barrels)			(per barrel)		
First Quarter 2009 through Fourth Quarter 2009	1,000		\$ 70.00	\$ 90.00 \$ 119.25		(1,128)
Frac Spread Collar	(in MMBtu)			(per MMBtu)		
First Quarter 2009 through Fourth Quarter 2009	6,000			\$ 9.09 \$ 13.94		1,435
Settlements to be paid in subsequent period						<u>(3,186)</u>
Natural gas midstream segment commodity derivatives - net liability						<u>\$ (11,735)</u>

Our management estimates that, excluding the derivative positions described above, for every \$1.00 per MMBtu increase or decrease in the natural gas price, natural gas midstream gross margin and operating income for the last three months of 2008 would increase or decrease by approximately \$1.4 million. In addition, our management estimates that for every \$5.00 per barrel increase or decrease in the oil price, natural gas midstream gross margin and operating income would increase or decrease by approximately \$1.8 million. This assumes that crude oil prices, natural gas prices and inlet volumes remain constant at forecasted levels. These estimated changes in gross margin and operating income exclude potential cash receipts or payments in settling these derivative positions.

Interest Rate Risk Management

As of September 30, 2008, we had \$558.1 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. We entered into the Revolver Swaps to effectively convert the interest rate on \$210.0 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 4.23% plus the applicable margin until March 2010. From March 2010 to December 2011, the Revolver Swaps will effectively convert the interest rate on \$150.0 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 4.23% plus the applicable margin. Certain of our Revolver Swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding under the Revolver (net of amounts fixed through hedging transactions) at September 30, 2008 would cost us approximately \$3.5 million in additional interest expense.

Item 4 *Controls and Procedures*

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of September 30, 2008. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of September 30, 2008, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

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

PART II. OTHER INFORMATION

Item 1 *Legal Proceedings*

Loadout LLC (“Loadout”), a subsidiary of ours, holds permits to mine at the Nellis Surface Mine in Boone County, West Virginia. The permits have been assigned to a mine operator who leases the property for mining, Coal River Mining, LLC (“Coal River”). The U.S. Army Corps of Engineers (“Corps”) issued a permit (the “Permit”) under Section 404 of the federal Clean Water Act to Loadout on April 16, 2008, authorizing the placement of fill material into certain waters of the United States in conjunction with the construction of four valley fills, three sediment pond embankments and one haul road at the Nellis Mine. On April 23, 2008, the plaintiffs in the suit *Ohio Valley Environmental Coalition v. U.S. Army Corps of Engineers*, No. 3:05-0784 (S.D. W. Va.) (the “OVEC suit”) filed a complaint and motion for a temporary restraining order (“TRO”) seeking to suspend or revoke the Permit, alleging, among other things, violations by the Corps of the National Environmental Policy Act and Clean Water Act. The plaintiffs subsequently filed a motion to withdraw their motion for a TRO, pending good-faith negotiations between the plaintiffs, Loadout, and Coal River to reach an agreement over the Permit. In September, those parties terminated negotiations without resolution, and in October, Loadout and Coal River filed a (i) formal reply in the OVEC suit, arguing against the addition of Loadout and Coal River as defendants and (ii) separate declaratory action to validate the issuance of the Permit. Because of the limited volume of projected coal to be produced from the Nellis Surface Mine relative to total production from all our holdings, it is not expected that either a settlement of this matter or a possible delay in proceeding with mining pending litigation would materially affect our business interests.

Item 1A *Risk Factors*

The following is an update to Item 1A – Risk Factors contained in our 2007 Annual Report on Form 10-K. For additional risk factors that could cause actual results to differ materially from those anticipated, please refer to our 2007 Annual Report on Form 10-K.

The current deterioration of the credit and capital markets may adversely impact our ability to obtain financing on acceptable terms or obtain funding under the Revolver. This may hinder or prevent us from implementing our development plan, completing acquisitions or otherwise meeting our future capital needs.

Global financial markets have been experiencing extreme volatility and disruption, and the debt and equity capital markets have been exceedingly distressed. These issues have made, and will likely continue to make, it difficult to obtain financing. In particular, the cost of raising money in the equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. The current global economic downturn may adversely impact our ability to issue additional equity in the future at prices which will not be dilutive to our existing unitholders or preclude us from issuing equity at all.

Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. Moreover, even if lenders and institutional investors are willing and able to provide adequate funding, interest rates may rise in the future and therefore increase the cost of borrowing we incur on any of our floating rate debt. In addition, we may be unable to obtain adequate funding under the Revolver because (i) our lending counterparties may be unwilling or unable to meet their funding obligations or (ii) our borrowing capacity may be reduced if there is an extensive decline in our EBITDA.

Due to these factors, we cannot be certain that funding will be available if needed and to the extent required on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, it might adversely affect our development plan as currently anticipated and our ability to complete acquisitions, each of which could have a material adverse effect on our revenues and results of operations.

Item 6 Exhibits

- 3.1 Third Amended and Restated Agreement of Limited Partnership of Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on August 7, 2008).
- 3.2 Limited Liability Company Agreement of PVR Finco LLC (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed on August 7, 2008).
- 10.1 Amended and Restated Credit Agreement, dated August 5, 2008, by and among PVR Finco LLC, the guarantors party thereto, PNC Bank, National Association, as Administrative Agent, and the other financial institutions party thereto.
- 10.2 Penn Virginia Resource GP, LLC Fourth Amended and Restated Long-Term Incentive Plan.
- 10.3 Amended and Restated Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Resource GP, LLC and Keith D. Horton (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 22, 2008).
- 10.4 Amended and Restated Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Resource GP, LLC and Ronald K. Page (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 22, 2008).
- 12.1 Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.
- 31.1 Certification Pursuant to Exchange Act Rule 13a-14(a) or Rule 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 Certification Pursuant to Exchange Act Rule 13a-14(a) or Rule 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PENN VIRGINIA RESOURCE PARTNERS, L.P.

By: PENN VIRGINIA RESOURCE GP, LLC

Date: November 6, 2008

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

Date: November 6, 2008

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)

	Years Ended December 31,					Nine Months
	2003	2004	2005	2006	2007	Ended September 30, 2008
Earnings						
Pre-tax income *	\$ 22,690	\$ 34,876	\$ 52,430	\$ 74,910	\$ 55,552	\$ 86,473
Fixed charges	5,048	7,328	14,351	19,783	19,766	19,038
Total earnings	\$ 27,738	\$ 42,204	\$ 66,781	\$ 94,693	\$ 75,318	\$ 105,511
Fixed Charges						
Interest expense **	\$ 4,986	\$ 7,267	\$ 14,053	\$ 19,151	\$ 18,896	\$ 18,040
Rental interest factor	62	61	298	632	870	998
Total fixed charges	\$ 5,048	\$ 7,328	\$ 14,351	\$ 19,783	\$ 19,766	\$ 19,038
Ratio of earnings to fixed charges	5.5x	5.8x	4.7x	4.8x	3.8x	5.5x

* Excludes equity earnings from investees.

** Includes capitalized interest.

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, A. James Dearlove, Chief Executive Officer of Penn Virginia Resource GP, LLC, the 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 (this "Report");
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 the board of directors of the general partner of the Registrant:
 - (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: November 6, 2008

/s/ A. James Dearlove

A. James Dearlove
Chief Executive Officer

**CERTIFICATION 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, the 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 (this "Report");
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 the board of directors of the general partner of the Registrant:
 - (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: November 6, 2008

/s/ Frank A. Pici

Frank A. Pici

Vice President and Chief Financial Officer

**CERTIFICATION 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 quarter ended September 30, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. James Dearlove, Chief Executive Officer of Penn Virginia Resource GP, LLC, 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.

Date: November 6, 2008

/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.

**CERTIFICATION 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 quarter ended September 30, 2008, 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 Penn Virginia Resource GP, LLC, 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.

Date: November 6, 2008

/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.