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, 2009

or

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

For the transition period from ______________ to ______________

Commission File Number: 1-16735

PENN VIRGINIA RESOURCE PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	23-3087517
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
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, 2009, 51,798,895 common units representing limited partner interests 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. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME – unaudited
(in thousands, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Revenues				
Natural gas midstream	$ 118,443	$ 241,282	$ 348,882	$ 601,127
Coal royalties	29,821	33,308	90,448	88,911
Coal services	1,869	1,815	5,502	5,518
Other	5,492	8,871	16,971	23,039
Total revenues	155,625	285,276	461,803	718,595
Expenses				
Cost of midstream gas purchased	92,355	211,262	285,129	513,778
Operating	9,030	9,041	26,938	24,553
Taxes other than income	1,005	969	3,208	3,017
General and administrative	7,568	7,078	23,421	20,339
Depreciation, depletion and amortization	17,851	16,903	51,971	41,322
Total expenses	127,809	245,253	390,667	603,009
Operating income	27,816	40,023	71,136	115,586
Other income (expense)				
Interest expense	(6,505)	(7,060)	(18,486)	(17,366)
Other	323	(4,153)	969	(3,233)
Derivatives	(2,810)	15,742	(12,005)	(6,424)
Net income	$ 18,824	$ 44,552	$ 41,614	$ 88,563
General partner's interest in net income	$ 6,291	$ 6,806	$ 18,576	$ 17,482
Limited partners' interest in net income	$ 12,533	$ 37,746	$ 23,038	$ 71,081
Basic and diluted net income per limited partner unit (see Note 6)	$ 0.24	$ 0.73	$ 0.43	$ 1.46
Weighted average number of units outstanding, basic and diluted	51,799	51,663	51,799	48,804

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

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

	September 30, 2009	December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 11,266	$ 9,484
Accounts receivable, net of allowance for doubtful accounts	60,023	73,267
Derivative assets	7,322	30,431
Other current assets	4,252	4,263
Total current assets	82,863	117,445
Property, plant and equipment	1,154,849	1,093,526
Accumulated depreciation, depletion and amortization	(244,855)	(198,407)
Net property, plant and equipment	909,994	895,119
Equity investments	87,520	78,442
Intangible assets, net	87,108	92,672
Other long-term assets	41,310	35,141
Total assets	$ 1,208,795	$ 1,218,819
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	$ 46,700	$ 60,390
Accrued liabilities	9,822	10,796
Deferred income	3,043	4,842
Derivative liabilities	10,900	13,585
Total current liabilities	70,465	89,613
Deferred income	6,502	6,150
Other liabilities	16,480	17,359
Derivative liabilities	4,323	6,915
Long-term debt	628,100	568,100
Partners' capital	482,925	530,682
Total liabilities and partners' capital	$ 1,208,795	$ 1,218,819

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Cash flows from operating activities				
Net income	$ 18,824	$ 44,552	$ 41,614	$ 88,563
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	17,851	16,903	51,971	41,322
Commodity derivative contracts:				
Total derivative losses (gains)	3,668	(14,239)	14,234	10,552
Cash settlements of derivatives	(314)	(14,054)	4,135	(33,279)
Non-cash interest expense	1,416	1,175	3,149	1,543
Equity earnings, net of distributions received	(1,385)	(1,409)	(2,456)	(1,415)
Other	1,199	(986)	569	(1,607)
Changes in operating assets and liabilities	1,608	(10,502)	3,209	(10,912)
Net cash provided by operating activities	42,867	21,440	116,425	94,767
Cash flows from investing activities				
Acquisitions	(27,648)	(156,791)	(29,510)	(253,031)
Additions to property, plant and equipment	(11,523)	(16,062)	(43,781)	(54,902)
Other	300	982	872	1,657
Net cash used in investing activities	(38,871)	(171,871)	(72,419)	(306,276)
Cash flows from financing activities				
Distributions to partners	(31,211)	(29,841)	(92,966)	(80,199)
Proceeds from borrowings	52,000	242,000	93,000	366,800
Repayments of borrowings	(21,000)	(65,400)	(33,000)	(220,800)
Net proceeds from issuance of partners' capital	-	-	-	140,958
Other	-	(3,454)	(9,258)	(4,074)
Net cash provided by (used in) activities	(211)	143,305	(42,224)	202,685
Net increase (decrease) in cash and cash equivalents	3,785	(7,126)	1,782	(8,824)
Cash and cash equivalents – beginning of period	7,481	17,832	9,484	19,530
Cash and cash equivalents – end of period	$ 11,266	$ 10,706	$ 11,266	$ 10,706
Supplemental disclosure:				
Cash paid for interest	$ 6,444	$ 6,764	$ 18,446	$ 17,136
Noncash investing activities:				
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.

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 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, 2009, Penn Virginia owned an approximately 51% limited partner interest in PVG, as well as the non-economic general partner interest in PVG. At September 30, 2009, 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. Basis of Presentation

Our condensed consolidated financial statements include the accounts of the Partnership and all of our wholly owned subsidiaries. Investments in non-controlled entities over which we exercise significant influence are accounted for using the equity method. 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. 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. Our condensed consolidated financial statements should be read in conjunction with our consolidated financial statements and footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2008. Operating results for the three and nine months ended September 30, 2009 are not necessarily indicative of the results that may be expected for the year ending December 31, 2009. Certain reclassifications have been made to conform to the current period's presentation. In preparing the accompanying condensed consolidated financial statements, we have evaluated subsequent events through November 5, 2009.

3. Fair Value Measurements

Effective January 1, 2009, we adopted the new accounting standard on fair value measurements and disclosures applicable to both our financial and nonfinancial assets and liabilities that are measured and reported on a fair value basis. Our financial instruments that are subject to fair value disclosures consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments and long-term debt. We have followed consistent methods and assumptions to estimate the fair values as more fully described in our Annual Report on Form 10-K for the year ended December 31, 2008. At September 30, 2009, the carrying values of all of these financial instruments approximated fair value.

The following table summarizes the valuation of certain assets and liabilities by category as of September 30, 2009 (in thousands):

		Fair Value Measurements at September 30, 2009, Using		
Description	Fair Value Measurements at September 30, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Interest rate swap assets - noncurrent	$ 1,138	$ -	$ 1,138	$ -
Interest rate swap liabilities - current	(8,188)	-	(8,188)	-
Interest rate swap liabilities - noncurrent	(4,117)	-	(4,117)	-
Commodity derivative assets - current	7,322	-	7,322	-
Commodity derivative assets - noncurrent	417	-	417	-
Commodity derivative liabilities - current	(2,712)	-	(2,712)	-
Commodity derivative liabilities - noncurrent	(206)	-	(206)	-
Total	$ (6,346)	$ -	$ (6,346)	$ -

See Note 4, “Derivative Instruments,” for the effects of derivative instruments on our condensed consolidated financial statements.

4. Derivative Instruments

Natural Gas Midstream Segment Commodity Derivatives

We determine the fair values of our derivative agreements using quoted forward prices for the respective commodities as of the end of the reporting period and discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position and our own credit risk if the derivative is in a liability position. The following table sets forth our positions as of September 30, 2009 for commodities related to natural gas midstream revenues and cost of midstream gas purchased:

			Weighted Average Price			
	Average Volume Per Day	Swap Price	Additional Put Option	Put	Call	Fair Value at September 30, 2009 (in thousands)
Crude Oil Three-Way Collar	**(barrels)**			**($ per barrel)**		
Fourth Quarter 2009	1,000		70.00	90.00	119.25	$ 1,433
Frac Spread Collar	**(MMBtu)**			**($ per MMBtu)**		
Fourth Quarter 2009	6,000			9.09	13.94	864
Crude Oil Collar	**(barrels)**			**($ per barrel)**		
First Quarter 2010 through Fourth Quarter 2010	750			70.00	81.25	228
First Quarter 2010 through Fourth Quarter 2010	1,000			68.00	80.00	(155)
Natural Gas Purchase Swap	**(MMBtu)**	**($ per MMbtu)**				
First Quarter 2010 through Fourth Quarter 2010	5,000	5.815				709
Settlements to be received in subsequent period						1,742
Natural gas midstream segment commodity derivatives - net asset						$ 4,821

See the “Financial Statement Impact of Derivatives” section below for the impact of our natural gas midstream commodity derivatives on our condensed consolidated financial statements.

Interest Rate Swaps

We have entered into interest rate swaps (the "Interest Rate Swaps") to establish fixed interest rates on a portion of the outstanding borrowings under our revolving credit facility (the "Revolver"). The following table sets forth the Interest Rate Swap positions at September 30, 2009:

Dates	Notional Amounts (in millions)		Weighted-Average Fixed Rate
Until March 2010	$	310.0	3.54%
March 2010 - December 2011	$	250.0	3.37%
December 2011 - December 2012	$	100.0	2.09%

During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps are recognized in the derivatives line item on our condensed consolidated statements of income. At September 30, 2009, a $2.2 million loss remained in accumulated other comprehensive income ("AOCI") related to the Interest Rate Swaps. The $2.2 million loss will be recognized in interest expense as the Interest Rate Swaps settle.

We reported a (i) net derivative liability of $11.2 million at September 30, 2009 and (ii) loss in AOCI of $2.2 million at September 30, 2009 related to the Interest Rate Swaps. In connection with periodic settlements, we reclassified a total of $2.6 million of net hedging losses on the Interest Rate Swaps from AOCI to interest expense during the nine months ended September 30, 2009. See the "Financial Statement Impact of Derivatives" section below for the impact of the Interest Rate Swaps on our condensed consolidated financial statements.

Financial Statement Impact of Derivatives

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, 2009 and 2008 (in thousands):

	Location of gain (loss) on derivatives recognized in income	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Derivatives de-designated as hedging instruments:					
Interest rate contracts (1)	Interest expense	$ (857)	$ (854)	$ (2,600)	$ (1,213)
Decrease in net income resulting from derivatives de-designated as hedging instruments		$ (857)	$ (854)	$ (2,600)	$ (1,213)
Derivatives not designated as hedging instruments:					
Interest rate contracts	Derivatives	$ (3,947)	$ (1,333)	$ (3,251)	$ (1,333)
Commodity contracts	Derivatives	1,137	15,572	(8,754)	(9,219)
Decrease in net income resulting from derivatives not designated as hedging instruments		$ (2,810)	$ 14,239	$ (12,005)	$ (10,552)
Total decrease in net income resulting from derivatives		$ (3,667)	$ 13,385	$ (14,605)	$ (11,765)
Realized and unrealized derivative impact:					
Cash received (paid) for commodity and interest rate	Derivatives	(314)	(14,054)	4,135	(33,279)
Cash paid for interest rate contract settlements	Interest expense	-	(854)	(370)	(1,213)
Unrealized derivative losses (2)		(3,353)	28,293	(18,370)	22,727
Total decrease in net income resulting from derivatives		$ (3,667)	$ 13,385	$ (14,605)	$ (11,765)

(1) Represents amounts reclassified out of AOCI and into interest expense. At September 30, 2009, a $2.2 million loss remained in AOCI related to the Interest Rate Swaps on which we discontinued hedge accounting.

(2) Represents net unrealized gains (losses) in the natural gas midstream, cost of midstream gas purchased, interest expense and derivatives line items on our condensed consolidated statements of income. For the three months ended September 30, 2009, the net unrealized derivative losses were composed of a $2.5 million unrealized loss on the Interest Rate Swaps and a $0.9 million unrealized loss on the commodity derivatives. For the nine months ended September 30, 2009, the net unrealized derivative losses were composed of a $0.5 million unrealized loss on the Interest Rates Swaps and a $17.9 million unrealized loss on our commodity derivatives.

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, 2009 and December 31, 2008 (in thousands):

		Fair values as of September 30, 2009		Fair values as of December 31, 2008	
	Balance Sheet Location	**Derivative Assets**	**Derivative Liabilities**	**Derivative Assets**	**Derivative Liabilities**
Derivatives de-designated as hedging instruments:					
Interest rate contracts	Derivative liabilities - current	$ -	$ -	$ -	$ 1,228
Interest rate contracts	Derivative liabilities - noncurrent	-	-	-	1,842
Total derivatives de-designated as hedging instruments		$ -	$ -	$ -	$ 3,070
Derivatives not designated as hedging instruments:					
Interest rate contracts	Derivative assets/liabilities - current	$ -	$ 8,188	$ -	$ 4,663
Interest rate contracts	Derivative assets/liabilities - noncurrent	1,138	4,117	-	5,073
Commodity contracts	Derivative assets/liabilities - current	7,322	2,712	30,431	7,694
Commodity contracts	Derivative assets/liabilities - noncurrent	417	206	-	-
Total derivatives not designated as hedging instruments		$ 8,877	$ 15,223	$ 30,431	$ 17,430
Total fair value of derivative instruments		$ 8,877	$ 15,223	$ 30,431	$ 20,500

See Note 3, "Fair Value Measurements," for a description of how the above-described financial instruments are valued.

The following table summarizes our interest expense for the three and nine months ended September 30, 2009 and 2008, including the effect of the Interest Rate Swaps (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Source	**2009**	**2008**	**2009**	**2008**
Interest on borrowings	$ 5,648	$ 6,206	$ 16,112	$ 16,828
Capitalized interest	-	-	(226)	(675)
Interest rate swaps	857	854	2,600	1,213
Total interest expense	$ 6,505	$ 7,060	$ 18,486	$ 17,366

At September 30, 2009, we reported a commodity derivative asset related to our natural gas midstream segment of $4.8 million. The contracts underlying such commodity derivative asset are with four counterparties, all of which are investment grade financial institutions, and such commodity derivative asset is substantially concentrated with one of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be equal to the fair value of the contracts as of September 30, 2009. No significant uncertainties related to the collectability of amounts owed to us exist with regard to these counterparties.

The above-described hedging activity represents cash flow hedges. As of September 30, 2009, we did not own derivative instruments that were classified as fair value hedges or trading securities or that contained credit risk contingencies.

5. Long-Term Debt

In March 2009, we increased the size of the Revolver from $700.0 million to $800.0 million, which resulted in $9.3 million of debt issuance costs that will be amortized over the remaining life of the Revolver. The Revolver is secured with substantially all of our assets. The December 2011 maturity date for the Revolver did not change. As of September 30, 2009, all of our long-term debt was indebtedness outstanding under the Revolver. Interest is payable at a base rate plus an applicable margin of up to 1.25% 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 1.75% to 2.75% if we select the LIBOR-based borrowing option. As of September 30, 2009 and December 31, 2008, the weighted average interest rate on borrowings outstanding under the Revolver was approximately 2.5% and 3.2%.

6. Partners' Capital and Distributions

As of September 30, 2009, 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, 2009, affiliates of Penn Virginia, in the aggregate, owned an approximately 39% interest in us, consisting of 19.6 million common units, representing an approximately 37% limited partner interest, and a 2% general partner interest.

Net Income per Limited Partner Unit

Effective January 1, 2009, we adopted the new accounting standard addressing the computation of earnings per unit for master limited partnerships that issue multiple classes of securities that participate in partnership distributions. Our securities consist of publicly traded common units held by limited partners, a general partner interest and separately transferable incentive distribution rights ("IDRs"). This standard requires earnings or losses for a reporting period to be allocated to our limited partners, our general partner and holders of IDRs using the two-class method to compute earnings per unit. Under this method, our net income (or loss) for a reporting period is reduced (or increased) by the amount that has been or will be distributed to our participating security holders. In the event that our net income exceeds our distributions (or our distributions exceed our net income), such excess undistributed net income (or loss) is allocated to our limited partners and our general partner in the ratio of 98% and 2%, as provided in our partnership agreement.

Also on January 1, 2009, we adopted the new accounting standard which determines whether instruments granted in share-based payments transactions are participating securities. Under this standard, unvested unit-based payment awards that contain non-forfeitable rights to distributions or distribution equivalents are participating securities and, therefore, are included in the computation of net income allocable to limited partners pursuant to the two-class method of computing earnings per unit. During the nine months ended September 30, 2009, our general partner granted phantom units to employees of our general partner or its affiliates. See Note 8, "Unit-Based Compensation." We have determined that our unvested phantom unit awards contain non-forfeitable rights to distributions and, therefore, are participating securities for purposes of this standard.

Basic and diluted net income per limited partner unit is computed by dividing net income allocable to limited partners by the weighted average number of limited partner units outstanding during the period. Diluted net income per limited partner unit is computed by dividing net income allocable to limited partners by the weighted average number of limited partner units outstanding during the period and, when dilutive, phantom units. For the three and nine months ended September 30, 2009, average awards of 105,000 and 112,000 phantom units were excluded from the diluted net income per limited partner unit calculation because the inclusion of these phantom units would have had an antidilutive effect.

The following table reconciles the computation of net income to net income allocable to limited partners (in thousands, except per unit data):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008 As Adjusted	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008 As Adjusted
Net income	$ 18,824	$ 44,552	$ 41,614	$ 88,563
Less:				
Distributions payable on account of incentive distribution rights	(6,035)	(6,035)	(18,105)	(16,032)
Distributions payable on account of general partner interest	(497)	(497)	(1,491)	(1,406)
General partner interest in excess of distributions over earnings (excess of earnings over distributions) allocable to the general partner interest	241	(274)	1,020	(44)
Net income allocable to limited partners and participating securities	$ 12,533	$ 37,746	$ 23,038	$ 71,081
Less:				
Distributions to participating securities	(166)	-	(501)	-
Participating securities' allocable share of net income	(83)	-	(152)	-
Net income allocable to limited partners	$ 12,284	$ 37,746	$ 22,385	$ 71,081
Weighted average limited partner units, basic and diluted	51,799	51,663	51,799	48,804
Net income per limited partner unit, basic and diluted	$ 0.24	$ 0.73	$ 0.43	$ 1.46

The foregoing amounts reflect the retroactive application of the two new accounting standards described above on certain previously reported items for the three and nine months ended September 30, 2008.

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 any other agreements and (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:

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

The following table reflects the allocation of total cash distributions paid by us during the three and nine months ended September 30, 2009 and 2008 (in thousands, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Limited partner units	$ 24,345	$ 23,827	$ 73,035	$ 64,862
General partner interest (2%)	497	486	1,491	1,323
Incentive distribution rights	6,035	5,528	18,105	14,014
Total cash distributions paid	$ 30,877	$ 29,841	$ 92,631	$ 80,199
Total cash distributions paid per limited partner unit	$ 0.47	$ 0.46	$ 1.41	$ 1.35

On November 13, 2009, we will pay a $0.47 per unit quarterly distribution to unitholders of record on November 6, 2009. This per unit distribution will remain unchanged from the previous distribution paid on August 14, 2009.

7. 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 $1.6 million and $1.5 million for the three months ended September 30, 2009 and 2008 and $4.7 million and $4.6 million for the nine months ended September 30, 2009 and 2008. These costs are reflected in the general and administrative expenses line item on 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 $4.3 million and $8.0 million as of September 30, 2009 and December 31, 2008. These amounts are primarily due to a wholly owned subsidiary of Penn Virginia, Penn Virginia Oil & Gas, L.P. ("PVOG LP"), and are related to the natural gas gathering and processing agreement between PVR East Texas Gas Processing, LLC ("PVR East Texas"), our wholly owned subsidiary, and PVOG LP. See "—Gathering and Processing Revenues." These balances are included in the accounts payable line item on our condensed consolidated balance sheets.

Marketing Revenues

PVOG LP 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, Connect Energy markets all of PVOG LP'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 LP 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 LP paid fees to Connect Energy of $0.3 million and $1.0 million for the three months ended September 30, 2009 and 2008 and $1.1 million and $2.5 million for the nine months ended September 30, 2009 and 2008. These marketing revenues are included in the other revenues line item on our condensed consolidated statements of income.

Gathering and Processing Revenues

PVR East Texas and PVOG LP are parties to a Gas Gathering and Processing Agreement effective May 1, 2007. Pursuant to the Gas Gathering and Processing Agreement, PVR East Texas gathers and processes all of PVOG LP's current and future gas production in certain areas of the Bethany Field in East Texas and redelivers the natural gas liquids ("NGLs") to PVOG LP for a $0.31 per one million British thermal units (MMBtu) service fee (with an annual CPI adjustment). The Gas Gathering and Processing Agreement has a primary term ending August 31, 2021 and automatically renews for additional one-year terms until terminated by either party. PVR East Texas began gathering and processing PVOG LP's gas in September 2008. Pursuant to the Gas Gathering and Processing Agreement, PVOG LP paid fees to PVR East Texas of $1.1 million and $0.7 million for the three months ended September 30, 2009 and 2008 and $3.2 million and $1.4 million in fees for the nine months ended September 30, 2009 and 2008. These gathering and processing revenues are recorded in the natural gas midstream revenues line item on our condensed consolidated statements of income.

Gas Purchases and Sales

From time to time, PVOG LP sells gas or NGLs to Connect Energy at our Crossroads plant, and Connect Energy transports them to the marketing location and then resells them to third parties. The sales price received by PVOG LP from Connect Energy for such gas or NGLs equals the sales price received by Connect Energy for such gas or NGLs from the third parties. These purchase and sale transactions do not impact our gross margin, nor do they impact our operating income. In the three months ended September 30, 2009 and 2008, we recorded $15.1 million and $55.7 million of natural gas midstream revenues and $15.1 million and $55.7 million for the cost of midstream gas purchased related to the purchase of natural gas from PVOG LP and the subsequent sale of that gas to third parties. In the nine months ended September 30, 2009 and 2008, we recorded $56.4 million and $105.5 million of natural gas midstream revenues and $56.4 million and $105.5 million for the cost of midstream gas purchased related to the purchase of natural gas from PVOG LP and the subsequent sale of that gas to third parties. We take title to the gas and NGLs prior to transporting them to third parties.

8. Unit-Based Compensation

The Penn Virginia Resource GP, LLC Fifth Amended and Restated Long-Term Incentive Plan (the "LTIP") permits the grant of common units, deferred common units, restricted units and phantom units to employees and directors of our general partner and its affiliates. We recognized compensation expense of $1.1 million and $0.8 million for the three months ended September 30, 2009 and 2008 and $3.9 million and $2.4 million for the nine months ended September 30, 2009 and 2008 related to the granting of common and deferred common units under the LTIP and the vesting of restricted units and phantom units granted under the LTIP. Common units and deferred common units granted under the LTIP are immediately vested, and we recognize compensation expense related to those grants on the grant date. Restricted units and phantom units granted under the LTIP vest over a three-year period, with one-third vesting in each year, and we recognize compensation expense related to those grants on a straight-line basis over the vesting period. These compensation expenses are recorded in the general and administrative expenses line item on our condensed consolidated statements of income.

9. 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, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 18,824	$ 44,552	$ 41,614	$ 88,563
Unrealized holding (losses) on derivative activities	-	(1,835)	(506)	(2,660)
Reclassification adjustment for derivative activities	857	3,691	2,600	6,675
Comprehensive income	$ 19,681	$ 46,408	$ 43,708	$ 92,578

10. 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 or results of operations.

Environmental Compliance

As of September 30, 2009 and December 31, 2008, our environmental liabilities were $1.1 million and $1.2 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.

Customer Credit Risk

For the nine months ended September 30, 2009, two of our natural gas midstream segment customers accounted for $83.0 million and $49.2 million, or 18% and 11%, of our total consolidated revenues. At September 30, 2009, 23% of our consolidated accounts receivable related to these customers.

11. Segment Information

Our reportable segments are as follows:

- Coal and Natural Resource Management—leasing of coal properties in exchange for royalty payments and other land management activities.
- 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 for the three and nine months ended September 30, 2009 and 2008 and as of September 30, 2009 and December 31, 2008 (in thousands):

	Revenues		Operating income (loss)	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2009	2008	2009	2008
Coal and natural resource management	$ 35,179	$ 41,660	$ 21,225	$ 26,295
Natural gas midstream	120,446	243,616	6,591	13,728
Consolidated totals	$ 155,625	$ 285,276	$ 27,816	$ 40,023
Interest expense			(6,505)	(7,060)
Other			323	(4,153)
Derivatives			(2,810)	15,742
Consolidated net income			$ 18,824	$ 44,552

	Additions to property and equipment		DD&A expenses	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2009	2008	2009	2008
Coal and natural resource management	$ 140	$ 497	$ 7,999	$ 8,794
Natural gas midstream	39,031	172,356	9,852	8,109
Consolidated totals	$ 39,171	$ 172,853	$ 17,851	$ 16,903

	Revenues		Operating income (loss)	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Coal and natural resource management	$ 108,575	$ 111,010	$ 66,532	$ 67,860
Natural gas midstream	353,228	607,585	4,604	47,726
Consolidated totals	$ 461,803	$ 718,595	$ 71,136	$ 115,586
Interest expense			(18,486)	(17,366)
Other			969	(3,233)
Derivatives			(12,005)	(6,424)
Consolidated net income			$ 41,614	$ 88,563

	Additions to property and equipment		DD&A expenses	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Coal and natural resource management	$ 2,046	$ 25,186	$ 23,557	$ 22,733
Natural gas midstream	71,245	282,747	28,414	18,589
Consolidated totals	$ 73,291	$ 307,933	$ 51,971	$ 41,322

	Total assets at	
	September 30, 2009	December 31, 2008
Coal and natural resource management	$ 568,829	$ 600,418
Natural gas midstream	639,966	618,401
Consolidated totals	$ 1,208,795	$ 1,218,819

12. New Accounting Standards

In September 2009, the Financial Accounting Standards Board issued guidance on how to measure the fair value of a liability when a quoted price in an active market for the identical liability is not available. It also includes other clarifications and examples of how to measure the fair value of certain liabilities, including those that have limited or no observable data. We do not expect the guidance to have a material impact on our condensed consolidated financial statements, and we will adopt it on its effective date of December 31, 2009.

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 Corporation in 2001, and we are principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States.

Selected Financial Data – Consolidated

The following table presents summary operating results for the three and nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues	$ 155,625	$ 285,276	$ 461,803	$ 718,595
Expenses	127,809	245,253	390,667	603,009
Operating income	27,816	40,023	71,136	115,586
Other income (expense)	(8,992)	4,529	(29,522)	(27,023)
Net income	$ 18,824	$ 44,552	$ 41,614	$ 88,563

We currently conduct operations in two business segments: (i) coal and natural resource management and (ii) natural gas midstream.

- Coal and Natural Resource Management—leasing of coal properties in exchange for royalty payments and other land management activities.
- Natural Gas Midstream—natural gas processing, gathering and other related services.

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

	Coal and Natural Resource Management	Natural Gas Midstream	Consolidated
For the Nine Months Ended September 30, 2009:			
Revenues	$ 108,575	$ 353,228	$ 461,803
Cost of midstream gas purchased	-	285,129	285,129
Operating costs and expenses	18,486	35,081	53,567
Depreciation, depletion and amortization	23,557	28,414	51,971
Operating income	$ 66,532	$ 4,604	$ 71,136
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	$ 67,860	$ 47,726	$ 115,586

Results of Operations

Coal and Natural Resource Management Segment

As of December 31, 2008, we owned or controlled approximately 827 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, 2009, our lessees produced 25.9 million tons of coal from our properties and paid us coal royalties revenues of $90.4 million, for an average royalty per ton of $3.50 ($3.33 per ton net of coal royalties expenses). Approximately 82% of our coal royalties revenues in the nine months ended September 30, 2009 was 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.

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.

The deterioration of the global economy, including financial and credit markets, has reduced worldwide demand for coal with resultant price declines. Depending on the longevity and ultimate severity of the deterioration, demand for coal may continue to decline, which could adversely affect production and pricing for coal mined by our lessees, and, consequently, adversely affect the royalty income received by us and our ability to make cash distributions to our partners. The deterioration of the global economy has also adversely affected credit availability and our access to new capital. This limited access to capital and credit availability has and could continue to hamper our ability to fund acquisitions, potentially restricting future growth potential.

Three and Nine Months Ended September 30, 2009 Compared with the Three and Nine Months Ended September 30, 2008

The following table sets forth a summary of certain financial and other data for our coal and natural resource management segment for the three and nine months ended September 30, 2009 and 2008 (in thousands, except as noted):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Financial Highlights				
Revenues				
Coal royalties	$ 29,821	$ 33,308	$ 90,448	$ 88,911
Coal services	1,869	1,815	5,502	5,518
Timber	1,582	1,911	4,355	5,328
Oil and gas royalty	535	1,940	1,783	4,730
Other	1,372	2,686	6,487	6,523
Total revenues	35,179	41,660	108,575	111,010
Expenses				
Coal royalties	1,587	2,125	4,380	8,034
Other operating	559	752	2,200	1,488
Taxes other than income	421	373	1,146	1,115
General and administrative	3,388	3,321	10,760	9,780
Depreciation, depletion and amortization	7,999	8,794	23,557	22,733
Total expenses	13,954	15,365	42,043	43,150
Operating income	$ 21,225	$ 26,295	$ 66,532	$ 67,860
Operating Statistics				
Royalty coal tons produced by lessees (tons in thousands)	8,387	8,496	25,874	24,975
Coal royalties revenues, net of coal royalties expenses	$ 28,234	$ 31,183	$ 86,068	$ 80,877
Average coal royalties revenues per ton ($/ton)	$ 3.56	$ 3.92	$ 3.50	$ 3.56
Less coal royalties expenses per ton ($/ton)	(0.19)	(0.25)	(0.17)	(0.32)
Average net coal royalties per ton ($/ton)	$ 3.37	$ 3.67	$ 3.33	$ 3.24

The following tables summarize coal production, coal royalties revenues and coal royalties per ton by region for the three and nine months ended September 30, 2009 and 2008:

Region	Coal Production Three Months Ended September 30, 2009 (tons in thousands)	2008	Coal Royalties Revenues Three Months Ended September 30, 2009 (in thousands)	2008	Coal Royalties Per Ton Three Months Ended September 30, 2009 ($/ton)	2008
Central Appalachia	4,594	4,815	$ 21,089	$ 25,184	$ 4.59	$ 5.23
Northern Appalachia	563	983	1,065	1,931	1.89	1.96
Illinois Basin	1,333	1,110	3,644	2,923	2.73	2.63
San Juan Basin	1,897	1,588	4,023	3,270	2.12	2.06
Total	8,387	8,496	$ 29,821	$ 33,308	$ 3.56	$ 3.92
Less coal royalties expenses (1)			(1,587)	(2,125)	(0.19)	(0.25)
Net coal royalties revenues			$ 28,234	$ 31,183	$ 3.37	$ 3.67

Region	Coal Production Nine Months Ended September 30, 2009 (tons in thousands)	2008	Coal Royalties Revenues Nine Months Ended September 30, 2009 (in thousands)	2008	Coal Royalties Per Ton Nine Months Ended September 30, 2009 ($/ton)	2008
Central Appalachia	13,902	14,770	$ 63,964	$ 68,213	$ 4.60	$ 4.62
Northern Appalachia	2,680	2,767	4,965	4,922	1.85	1.78
Illinois Basin	3,739	3,262	9,747	7,173	2.61	2.20
San Juan Basin	5,553	4,176	11,772	8,603	2.12	2.06
Total	25,874	24,975	$ 90,448	$ 88,911	$ 3.50	$ 3.56
Less coal royalties expenses (1)			(4,380)	(8,034)	(0.17)	(0.32)
Net coal royalties revenues			$ 86,068	$ 80,877	$ 3.33	$ 3.24

(1) Our coal royalties expenses are incurred primarily in the Central Appalachian region.

Production. Coal production decreased by 0.1 million tons, or 1%, from 8.5 million tons in the three months ended September 30, 2008 to 8.4 million tons in the same period of 2009. This decrease was primarily driven by decreased longwall production in the Northern Appalachian region resulting from adverse geological conditions hampering production and recovery. Additionally, there were decreases in the Central Appalachia region primarily attributable to production cutbacks due to a depressed coal market. 2009 production in the Central Appalachian region also decreased due to cutbacks in longwall mining operations that were prevalent during 2008. Production from one lessee ceased in the third quarter of 2008 as its operations moved onto adjacent reserves. These production decreases were partially offset by production increases in both the Illinois and San Juan Basins. The Illinois Basin production increased primarily due to the recognition of royalties and tonnages for previously mined reserves held in escrow pending property ownership research. The San Juan Basin benefited from the start up of a second mine and improved mining conditions in the region.

Coal production increased by 0.9 million tons, or 4%, from 25.0 million tons in the nine months ended September 30, 2008 to 25.9 million tons in the same period of 2009. The year to date increase in production primarily resulted from the start up of a second mine and improved mining conditions in the San Juan Basin, as well as the third quarter 2009 royalty and tonnage adjustment in the Illinois Basin for previously mined reserves temporarily held in escrow as ownership research was conducted. Partially offsetting these increases was the decline of 2009 production in the Central Appalachian region primarily in response to a depressed coal market, most notably in the metallurgical market where coal demand has fallen drastically since the third quarter of 2008. Also contributing to the production decrease in the Central Appalachia region was the reduction in longwall mining activity compared to the same period in 2008.

Revenues. Net coal royalties revenues decreased by $3.0 million, or 10%, from $31.2 million in the three months ended September 30, 2008 to $28.2 million in the same period of 2009. This decrease was primarily attributable to lower coal sales prices in Central Appalachia which in turn resulted in lower royalty revenues, and, to a lesser extent, to lower coal volumes sold from our properties. The average net coal royalty per ton, which represents the average coal royalties revenues per ton net of coal royalties expenses per ton, decreased by $0.30 per ton, or 8%, from $3.67 per ton in the three months ended September 30, 2008 to $3.37 per ton in the same period of 2009. This decrease was attributable to a $0.36 per ton decrease in average coal royalties revenues per ton, partially offset by a $0.06 per ton decrease in coal royalties expenses. Average coal royalties revenues per ton decreased the most in the Central Appalachian region primarily due to significantly reduced demand for metallurgical coal in the international coal markets.

Coal services revenues remained relatively constant from the three months ended September 30, 2008 to the same period of 2009. Timber revenues decreased by $0.3 million, or 16%, from $1.9 million in the three months ended September 30, 2008 to $1.6 million in the same period of 2009 primarily due to lower sales prices resulting from weakened market conditions for furniture-grade wood products. Oil and gas royalties revenues decreased by $1.4 million, or 74%, from $1.9 million in the three months ended September 30, 2008 to $0.5 million in the same period of 2009 primarily due to lower natural gas prices. Other revenues, which consisted primarily of wheelage fees, forfeiture income and management fees, decreased by $1.3 million, or 48%, from $2.7 million in the three months ended September 30, 2008 to $1.4 million in the same period of 2009 primarily due to lower wheelage income.

Net coal royalties revenues increased by $5.2 million, or 6%, from $80.9 million in the nine months ended September 30, 2008 to $86.1 million in the same period of 2009. This increase was attributable to increases in both production and average net coal sales prices received by our lessees. The average net coal royalty per ton increased by $0.09 per ton, or 3%, from $3.24 per ton in the nine months ended September 30, 2008 to $3.33 per ton in the same period of 2009. This increase was attributable to both an increase in the average coal royalties revenues per ton for most regions, especially in the Illinois Basin, where new contract pricing has generated higher gross sales prices for tonnages in that region, and lower coal royalties expenses caused by lower production from certain subleased properties.

Coal services revenues remained relatively constant from the nine months ended September 30, 2008 to the same period of 2009. Timber revenues decreased by $0.9 million, or 17%, from $5.3 million in the nine months ended September 30, 2008 to $4.4 million in the same period of 2009 primarily due to lower sales prices resulting from weakened market conditions for furniture-grade wood products. Oil and gas royalties revenues decreased by $2.9 million, or 62%, from $4.7 million in the nine months ended September 30, 2008 to $1.8 million in the same period of 2009 primarily due to lower natural gas prices. Other revenues remained relatively constant from the nine months ended September 30, 2008 to the same period of 2009.

Expenses. Other operating expenses decreased by $0.2 million, or 25%, from $0.8 million in the three months ended September 30, 2008 to $0.6 million in the same period of 2009 primarily due to lower expenses related to core drilling and mine maintenance costs for which we are contractually obligated. Taxes other than income and general and administrative expenses remained relatively constant from the three months ended September 30, 2008 to the same period of 2009. Depreciation, depletion and amortization expenses decreased by $0.8 million, or 9%, from $8.8 million in the three months ended September 30, 2008 to $8.0 million in the same period of 2009 primarily due to lower depletion expenses for our mining and timber operations.

Other operating expenses increased by $0.7 million, or 47%, from $1.5 million in the nine months ended September 30, 2008 to $2.2 million in the same period of 2009 primarily due to higher expenses related to our timber operations and costs incurred under our contractual obligations for mine maintenance. Taxes other than income remained relatively constant from the nine months ended September 30, 2008 to the same period of 2009. General and administrative costs increased by $1.0 million, or 10%, from $9.8 million in the nine months ended September 30, 2008 to $10.8 million in the same period of 2009 primarily due to higher staffing and related employee benefit costs. Depreciation, depletion and amortization expenses increased by $0.9 million, or 4%, from $22.7 million in the nine months ended September 30, 2008 to $23.6 million in the same period of 2009 primarily due to higher depletion expenses for our mining and timber operations.

Natural Gas Midstream Segment

Our natural gas midstream segment provides natural gas processing, gathering and other related services. As of September 30, 2009, we owned and operated natural gas midstream assets located in Oklahoma and Texas, including six natural gas processing facilities having 400 million cubic feet per day (MMcfd) of total capacity and approximately 4,069 miles of natural gas gathering pipelines. Our natural gas midstream business earns revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. In addition, we own a 25% member interest in Thunder Creek Gas Services, LLC, or Thunder Creek, a joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. 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.

During the three months ended September 30, 2009, we completed a 40 MMcfd plant expansion in our Beaver/Spearman complex, or the Panhandle System, in Texas and Oklahoma in July and acquired an additional 60 MMcfd plant in Oklahoma that began accepting gas on September 1, 2009. This additional processing capacity allows us to process all of our Panhandle natural gas through our own facilities and eliminate fees paid to third parties for processing services. We also acquired a 50% member interest in a residue pipeline connected to our east Texas processing plant.

For the nine months ended September 30, 2009, system throughput volumes at our gas processing plants and gathering systems, including gathering-only volumes, were 93.4 billion cubic feet (Bcf), or approximately 342 MMcfd. For the nine months ended September 30, 2009, 23% and 14% of our natural gas midstream segment's revenues and 18% and 11% of our total consolidated revenues were derived from two of our natural gas midstream segment's customers, Conoco, Inc. and Tenaska Marketing Ventures.

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. In the nine months ended September 30, 2009, our natural gas midstream segment made aggregate capital expenditures of $72.0 million, primarily related to the Panhandle System in Texas and Oklahoma.

Revenues, profitability and the future rate of growth of our natural gas midstream segment are highly dependent on market demand and prevailing natural gas liquid, or NGL, and natural gas prices. 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 demand. The deterioration of the global economy has resulted in a decrease in 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 affect our natural gas midstream processing income and our ability to make cash distributions. The deterioration of the global economy has also adversely affected credit availability and our access to new capital. This limited access to capital and credit availability has and could continue to hamper our ability to fund acquisitions, potentially restricting future growth potential.

Three and Nine Months Ended September 30, 2009 Compared with the Three and Nine Months Ended September 30, 2008

The following table sets forth a summary of certain financial and other data for our natural gas midstream segment for the three and nine months ended September 30, 2009 and 2008 (in thousands, except as noted):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Financial Highlights				
Revenues				
Residue gas	$ 62,801	$ 158,709	$ 211,165	$ 373,913
Natural gas liquids	48,147	72,349	117,670	199,053
Condensate	4,659	7,202	11,507	21,870
Gathering, processing and transportation fees	2,836	3,022	8,540	6,291
Total natural gas midstream revenues (1)	118,443	241,282	348,882	601,127
Equity earnings in equity investment	1,597	981	3,345	1,537
Producer services	406	1,353	1,001	4,921
Total revenues	120,446	243,616	353,228	607,585
Expenses				
Cost of midstream gas purchased (1)	92,355	211,262	285,129	513,778
Operating	6,884	6,164	20,358	15,031
Taxes other than income	584	596	2,062	1,902
General and administrative	4,180	3,757	12,661	10,559
Depreciation and amortization	9,852	8,109	28,414	18,589
Total operating expenses	113,855	229,888	348,624	559,859
Operating income	$ 6,591	$ 13,728	$ 4,604	$ 47,726
Operating Statistics				
System throughput volumes (MMcf)	29,811	27,744	93,433	68,915
Daily throughput volumes (MMcfd)	324	302	342	252
Gross margin	$ 26,088	$ 30,020	$ 63,753	$ 87,349
Cash impact of derivatives	1,993	(12,551)	9,162	(29,151)
Gross margin, adjusted for impact of derivatives	$ 28,081	$ 17,469	$ 72,915	$ 58,198
Gross margin ($/Mcf)	$ 0.88	$ 1.08	$ 0.68	$ 1.27
Cash impact of derivatives ($/Mcf)	0.06	(0.45)	0.10	(0.42)
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 0.94	$ 0.63	$ 0.78	$ 0.85

(1) In the three months ended September 30, 2009, we recorded $15.1 million of natural gas midstream revenues and $15.1 million for the cost of midstream gas purchased related to the purchase of natural gas from Penn Virginia Oil & Gas, L.P., or PVOG LP, and the subsequent sale of that gas to third parties. In the nine months ended September 30, 2009, we recorded $56.4 million of natural gas midstream revenues and $56.4 million for the cost of midstream gas purchased related to the purchase of natural gas from PVOG LP and the subsequent sale of that gas to third parties. We take title to the gas prior to transporting it to third parties.

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 include residue gas sold from processing plants after NGLs are 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 consists of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

The 13% gross margin decrease in the three months ended September 30, 2009 as compared to the same period of 2008 was primarily due to lower commodity pricing and frac spreads. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per million British thermal unit (MMBtu) basis. The gross margin decrease was partially offset by margins earned from higher system throughput volumes.

System throughput volumes increased by 22 MMcfd, or 7%, from 302 MMcfd in the three months ended September 30, 2008 to 324 MMcfd in the same period of 2009 primarily due to the continued successful development by producers operating in the vicinity of the Panhandle System, as well as our success in contracting and connecting new supply.

During the three months ended September 30, 2009, we generated a majority of our 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. See Note 4, "Derivative Instruments," in the Notes to Condensed Consolidated Financial Statements in Item 1, "Financial Statements," for a description of our derivatives program. Adjusted for the cash impact of our commodity derivative instruments, our gross margin increased by $10.6 million, or 61%, from $17.5 million in the three months ended September 30, 2008 to $28.1 million in the same period of 2009. On a per thousand cubic feet (Mcf) basis, adjusted for the cash impact of our commodity derivatives, our gross margin increased by $0.31 per Mcf, or 49%, from $0.63 per Mcf in the three months ended September 30, 2008 to $0.94 per Mcf in the same period of 2009. This increase was primarily attributable to changes in commodity prices and the mix of our commodity derivatives.

The 27% gross margin decrease in the nine months ended September 30, 2009 as compared to the same period of 2008 was a result of lower commodity pricing and frac spreads, partially offset by margins earned from higher system throughput volumes.

System throughput volumes increased by 90 MMcfd, or 36%, from 252 MMcfd in the nine months ended September 30, 2008 to 342 MMcfd in the same period of 2009 primarily due to the continued successful development by producers operating in the vicinity of the Panhandle System, as well as our success in contracting and connecting new supply. The Crossroads plant in East Texas, which became fully operational in April 2008, and the acquisition of our North Texas gathering system, which was consummated in the third quarter of 2008, also contributed to the volume increase.

Adjusted for the cash impact of our commodity derivative instruments, our gross margin increased by $14.7 million, or 25%, from $58.2 million in the nine months ended September 30, 2008 to $72.9 million in the same period of 2009. On a per Mcf basis, adjusted for the cash impact of our commodity derivatives, our gross margin decreased by $0.07 per Mcf, or 8%, from $0.85 per Mcf in the nine months ended September 30, 2008 to $0.78 per Mcf in the same period of 2009. This decrease was primarily attributable to the addition of lower margin fixed fee volumes at the Crossroads plant and from our recently acquired North Texas gathering system.

Equity Earnings in Equity Investment. Our equity earnings increased in both the three and nine months ended September 30, 2009 as compared to the same periods of 2008 primarily as a result of revenues generated from our 25% member interest in the Thunder Creek joint venture that gathers and transports coalbed methane in Wyoming's Powder River Basin. In 2009, revenues from this joint venture have grown primarily due to mainline volume increases despite the reduction in drilling in the Powder River Basin.

Producer Services Revenues. Producer services revenues decreased by $1.0 million, or 71%, from $1.4 million in the three months ended September 30, 2008 to $0.4 million in the same period of 2009 primarily due to a negative relative change in the natural gas indices on which our purchases and sales of natural gas are based and a decrease in marketing fees resulting from lower commodity prices.

Producer services revenues decreased by $3.9 million, or 80%, from $4.9 million in the nine months ended September 30, 2008 to $1.0 million in the same period of 2009 primarily due to a negative relative change in the natural gas indices on which our purchases and sales of natural gas are based and a decrease in marketing fees resulting from lower commodity prices.

Expenses. Operating expenses increased by $0.7 million, or 11%, from $6.2 million in the three months ended September 30, 2008 to $6.9 million in the same period of 2009 primarily due to higher costs for compressor rentals related to our expanding footprint in the Texas and Oklahoma panhandle. General and administrative expenses increased by $0.4 million, or 11%, from $3.8 million in the three months ended September 30, 2008 to $4.2 million in the same period of 2009 primarily due to higher staffing and related employee benefit costs. Depreciation and amortization expenses increased by $1.8 million, or 22%, from $8.1 million in the three months ended September 30, 2008 to $9.9 million in the same period of 2009 primarily due to capital spending on expansion projects, such as the Spearman and Crossroads plants, and our recent acquisitions.

Operating expenses increased by $5.4 million, or 36%, from $15.0 million in the nine months ended September 30, 2008 to $20.4 million in the same period of 2009 primarily due to higher costs for compressor rentals, employee costs and general supplies needed to operate assets in the Texas and Oklahoma panhandle. General and administrative expenses increased by $2.1 million, or 20%, from $10.6 million in the nine months ended September 30, 2008 to $12.7 million in the same period of 2009 primarily due to higher staffing and related employee benefit costs. Depreciation and amortization expenses increased by $9.8 million, or 53%, from $18.6 million in the nine months ended September 30, 2008 to $28.4 million in the same period of 2009 primarily due to capital spending on expansion projects, such as the Spearman and Crossroads plants, and our recent acquisitions.

Other

Our other results consist of interest expense and derivative gains and losses. The following table sets forth a summary of certain financial data for our other results for the three and nine months ended September 30, 2009 and 2008 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Operating income	$ 27,816	$ 40,023	$ 71,136	$ 115,586
Other income (expense)				
Interest expense	(6,505)	(7,060)	(18,486)	(17,366)
Other	323	(4,153)	969	(3,233)
Derivatives	(2,810)	15,742	(12,005)	(6,424)
Net income	$ 18,824	$ 44,552	$ 41,614	$ 88,563

Interest Expense. Interest expense for the three and nine months ended September 30, 2009 and 2008 is comprised of the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Source	2009	2008	2009	2008
Interest on borrowings	$ 5,648	$ 6,206	$ 16,112	$ 16,828
Capitalized interest	-	-	(226)	(675)
Interest rate swaps	857	854	2,600	1,213
Total interest expense	$ 6,505	$ 7,060	$ 18,486	$ 17,366

Interest expense incurred on borrowings under our revolving credit facility, or the Revolver, for both the three and nine months ended September 30, 2009 decreased from the comparative periods in 2008 due to lower interest rates. This decrease was partially offset by the effects of an increase in our weighted average borrowings due to our capital spending program and an increase in non-cash interest expense related to debt issuance costs incurred in March 2009. Our interest rate swaps, or the Interest Rate Swaps, which establish fixed interest rates on a portion of the outstanding borrowings under the Revolver, have also increased the total interest expense.

Derivatives. Our results of operations and operating cash flows were impacted by changes in market prices affecting fair values for NGL, crude oil and natural gas prices. Commodity markets are volatile, and as a result, our hedging activity results can vary significantly. We determine the fair values of our commodity derivative instruments using quoted forward prices for the respective commodities and discount rates adjusted for the credit risk of our counterparties for derivatives in an asset position and our own credit risk for derivatives in a liability position.

Our derivative activity for the three and nine months ended September 30, 2009 and 2008 is summarized below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Interest Rate Swap unrealized derivative gain (loss)	$ (1,640)	$ -	$ 1,776	$ -
Interest Rate Swap realized derivative loss	(2,307)	-	(5,027)	-
Natural gas midstream commodity unrealized derivative gain (loss)	(856)	29,796	(17,916)	26,855
Natural gas midstream commodity realized derivative gain (loss)	1,993	(14,054)	9,162	(33,279)
Total derivative gain (loss)	$ (2,810)	$ 15,742	$ (12,005)	$ (6,424)

Liquidity and Capital Resources

On an ongoing basis, we generally satisfy our working capital requirements and fund our capital expenditures using cash generated from our operations, borrowings under our $800.0 million Revolver and proceeds from equity offerings. As discussed in more detail in "—Long-Term Debt" below, as of September 30, 2009, we had availability of $170.3 million on the Revolver. We fund our debt service obligations and distributions to unitholders solely using cash generated from our operations. 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), interest payments on amounts outstanding under the Revolver and our distribution payments for the remainder of 2009. However, our ability to meet these requirements in the future will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond our control.

Cash Flows

The following table summarizes our cash flow statements for the nine months ended September 30, 2009 and 2008 (in thousands):

	Nine Months Ended September 30,	
	2009	2008
Cash flows from operating activities:		
Net income contribution	$ 41,614	$ 88,563
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	71,602	17,116
Net changes in operating assets and liabilities	3,209	(10,912)
Net cash provided by operating activities	116,425	94,767
Net cash used in investing activities	(72,419)	(306,276)
Net cash provided by (used in) financing activities	(42,224)	202,685
Net increase (decrease) in cash and cash equivalents	$ 1,782	$ (8,824)

Operating Activities. At September 30, 2009, we had $11.3 million in cash and cash equivalents compared to $9.5 million at December 31, 2008. Cash provided by operating activities for the nine months ended September 30, 2009 was $116.4 million compared to $94.8 million for the nine months ended September 30, 2008. This increase was due primarily to a significant change in cash settlements from derivatives, with net receipts of $4.1 million for the nine months ended September 30, 2009 compared with net payments of $33.3 million for the same period of 2008, partially offset by lower gross margin from our midstream segment in the nine month period of 2009.

Investing Activities. Cash used in investing activities was $72.4 million for the nine months ended September 30, 2009 compared to $306.3 million for the nine months ended September 30, 2008. This decrease was due to lower acquisition activity during the nine months ended September 30, 2009 compared to the same period of 2008.

Financing Activities. Cash used in financing activities was $42.2 million for the nine months ended September 30, 2009 compared to cash provided of $202.7 million for the nine months ended September 30, 2008. During the nine months ended September 30, 2008, an equity issuance provided net proceeds of $141.0 million and was used in part to repay borrowings under the Revolver. The proceeds from borrowings during both periods were used to fund our capital expenditures.

Long-Term Debt

In March 2009, we increased the size of the Revolver from $700.0 million to $800.0 million, which resulted in $9.3 million of debt issuance costs. The Revolver is secured with substantially all of our assets. As of September 30, 2009, we had remaining borrowing capacity of $170.3 million on the Revolver, net of outstanding borrowings of $628.1 million and letters of credit of $1.6 million. 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. Interest is payable at a base rate plus an applicable margin of up to 1.25% if we select the base rate borrowing option or at a rate derived from the London Interbank Offered Rate, or LIBOR, plus an applicable margin ranging from 1.75% to 2.75% if we select the LIBOR-based borrowing option. At September 30, 2009, the base rate applicable margin was 0.75% and the LIBOR-based rate applicable margin was 2.25%. At September 30, 2009, the weighted average interest rate on borrowings outstanding under the Revolver was approximately 2.5%. We entered into the Interest Rate Swaps to establish fixed interest rates on a portion of the outstanding borrowings under the Revolver. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk," for a discussion of the Interest Rate Swaps. As of September 30, 2009, we were in compliance with all of our covenants under the Revolver.

Future Capital Needs and Commitments

We believe that short-term cash requirements for operating expenses and quarterly distributions to our general partner and our unitholders will be funded through operating cash flows. We also believe that our remaining borrowing capacity will be sufficient for our capital needs and commitments for the remainder of 2009. Subject to commodity prices and the availability of capital, we are committed to the growth of both of our business segments through a combination of organic projects and acquisitions of new properties and assets. For the remainder of 2009, we anticipate making capital expenditures of approximately $11.0 to $19.0 million. The majority of our 2009 capital expenditures are expected to be incurred in our natural gas midstream segment.

Long-term cash requirements for acquisitions and other capital expenditures are expected to be funded by several sources, including cash flows from operating activities, borrowings under the Revolver and the issuance of additional debt and equity securities if available on commercially acceptable terms. However, disruptions in the global financial and commodities markets and the general economic climate have made access to equity and debt capital markets very difficult since late in 2008. While signs of improvement in these markets have occurred, if we are unable to access the capital markets for an extended period, our ability to make acquisitions and other capital expenditures, as well as our ability to increase or sustain cash distributions to our partners will likely become impaired. If additional financing is required, there are no assurances that it will be available or, if available, that it can be obtained on terms favorable to us.

Environmental Matters

Our operations and those of our coal 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 environment-related material adverse impact on our financial condition or results of operations.

As of September 30, 2009 and December 31, 2008, our environmental liabilities were $1.1 million and $1.2 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.

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. Our most critical accounting policies which involve the judgment of our management were fully disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008 and remained unchanged as of September 30, 2009.

Recent Accounting Pronouncements

See Note 12, "New Accounting Standards," in the Notes to 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 and coal;
- our ability to access external sources of capital;
- any impairment writedowns of our assets;
- 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 businesses;
- 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 our Annual Report on Form 10-K for the year ended December 31, 2008.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission, including our Annual Report on Form 10-K for the year ended December 31, 2008. 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 as follows:

- Price Risk
- Interest Rate Risk
- Customer Credit Risk

As a result of our 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 has heightened due to the deterioration of the global economy, including financial and credit markets.

Price Risk

Our price risk management program permits the utilization of derivative financial instruments (such as swaps, costless collars and three-way collars) 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 segment. The derivative financial instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our price derivative financial instruments are significantly affected by fluctuations in the prices of natural gas, NGLs and crude oil.

At September 30, 2009, we reported a commodity derivative asset related to our natural gas midstream segment of $4.8 million. The contracts underlying such commodity derivative asset are with four counterparties, all which are investment grade financial institutions, and such commodity derivative asset is substantially concentrated with one of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be equal to the fair value of the contracts as of September 30, 2009. No significant uncertainties related to the collectability of amounts owed to us exist with regard to these counterparties.

For the nine months ended September 30, 2009, we reported net derivative losses of $12.0 million. Because we no longer use hedge accounting for our commodity derivatives, we recognize changes in fair value in earnings currently in the derivatives line item on our condensed consolidated statements of income. 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 our commodity derivative contracts. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment. See Note 4, “Derivative Instruments,” in the Notes to Condensed Consolidated Financial Statements in Item 1, “Financial Statements,” for a further description of our derivatives program.

The following table lists our commodity derivative agreements and their fair values as of September 30, 2009:

	Average Volume Per Day	Swap Price	Weighted Average Price: Additional Put Option	Put	Call	Fair Value at September 30, 2009 (in thousands)
Crude Oil Three-Way Collar	**(barrels)**			**($ per barrel)**		
Fourth Quarter 2009	1,000		70.00	90.00	119.25	$ 1,433
Frac Spread Collar	**(MMBtu)**			**($ per MMBtu)**		
Fourth Quarter 2009	6,000			9.09	13.94	864
Crude Oil Collar	**(barrels)**			**($ per barrel)**		
First Quarter 2010 through Fourth Quarter 2010	750			70.00	81.25	228
First Quarter 2010 through Fourth Quarter 2010	1,000			68.00	80.00	(155)
Natural Gas Purchase Swap	**(MMBtu)**	**($ per MMbtu)**				
First Quarter 2010 through Fourth Quarter 2010	5,000	5.815				709
Settlements to be received in subsequent period						1,742
Natural gas midstream segment commodity derivatives - net asset						$ 4,821

We estimate that a $5.00 per barrel increase in the crude oil price would decrease the fair value of our crude oil collars by $0.8 million. We estimate that a $5.00 per barrel decrease in the crude oil price would increase the fair value of our crude oil collars by $4.8 million. We estimate that a $1.00 per MMBtu increase in the natural gas price would increase the fair value of our natural gas purchase swap by $2.5 million. We estimate that a $1.00 per MMBtu decrease in the natural gas price would decrease the fair value of our natural gas purchase swap by $1.1 million.

In addition, we estimate that a $1.00 per MMBtu increase in the natural gas purchase price and a $4.65 per barrel increase in the natural gasoline (a natural gas liquid) sales price would increase the fair value of our frac spread collar by $2.0 million. We estimate that a $1.00 per MMBtu decrease in the natural gas purchase price and a $4.65 per barrel decrease in the natural gasoline sales price would increase the fair value of our frac spread collar by $2.1 million. These estimated changes exclude potential cash receipts or payments in settling these derivative positions.

We estimate that, excluding the effects of derivative positions described above, for every $1.00 per MMBtu increase or decrease in the natural gas price, our natural gas midstream gross margin and operating income for the remainder of 2009 would increase or decrease by $1.3 million. In addition, we estimate that for every $5.00 per barrel increase or decrease in the crude oil price, our natural gas midstream gross margin and operating income for the remainder of 2009 would increase or decrease by $1.2 million. This assumes that natural gas prices, crude oil prices and inlet volumes remain constant at anticipated levels. These estimated changes in our gross margin and operating income exclude potential cash receipts or payments in settling these derivative positions.

Interest Rate Risk

As of September 30, 2009, we had $628.1 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. We entered into the Interest Rate Swaps to establish fixed interest rates on a portion of the outstanding borrowings under the Revolver. Until March 2010, the notional amounts of the Interest Rate Swaps total $310.0 million, or 49.4% of our outstanding indebtedness under the Revolver as of September 30, 2009, with us paying a weighted average fixed rate of 3.54% 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 Interest Rate Swaps total $250.0 million, or 39.8% of our outstanding indebtedness under the Revolver as of September 30, 2009, with us paying a weighted average fixed rate of 3.37% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From December 2011 to December 2012, the notional amounts of the Interest Rate Swaps total $100.0 million, or 15.9% of our outstanding indebtedness under the Revolver as of September 30, 2009,with us paying a weighted average fixed rate of 2.09% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The Interest Rate Swaps extend one year past the current maturity of the Revolver. A 1% increase in short-term interest rates on the floating rate debt outstanding under the Revolver (net of amounts fixed through the Interest Rate Swaps) as of September 30, 2009 would cost us approximately $3.2 million in additional interest expense per year.

During the first quarter of 2009, we discontinued hedge accounting for all of the Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Interest Rate Swaps are recognized in earnings currently. Therefore, our results of operations are affected by the volatility of changes in fair value, which fluctuates with changes in interest rates. These fluctuations could be significant. See Note 4, "Derivative Instruments," in the Notes to Condensed Consolidated Financial Statements in Item 1, "Financial Statements," for a further description of our derivatives program.

Customer Credit Risk

We are exposed to the credit risk of our natural gas midstream customers and coal lessees. For the nine months ended September 30, 2009, two of our natural gas midstream segment customers accounted for $83.0 million and $49.2 million, or 18% and 11%, of our total consolidated revenues. At September 30, 2009, 23% of our consolidated accounts receivable related to these customers. No significant uncertainties related to the collectability of amounts owed to us exist in regard to these two natural gas midstream customers.

This customer concentration increases our exposure to credit risk on our accounts receivables, because the financial insolvency of any of these customers could have a significant impact on our results of operations. If our natural gas midstream customers or coal lessees become financially insolvent, they may not be able to continue to operate or meet their payment obligations to us. Any material losses as a result of customer or lessee defaults could harm and have an adverse effect on our business, financial condition or results of operations. Substantially all of our trade accounts receivable are unsecured.

To mitigate the risks of nonperformance by our natural gas midstream customers, we perform ongoing credit evaluations of our existing customers. We monitor individual customer payment capability in granting credit arrangements to new customers by performing credit evaluations, seek to limit credit to amounts we believe the customers can pay and maintain reserves we believe are adequate to cover exposure for uncollectible accounts. As of September 30, 2009, no receivables were collateralized, and we had a $1.4 million allowance for doubtful accounts, of which $1.3 million was related to our natural gas midstream segment.

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, 2009. 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, 2009, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

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

PART II.   OTHER INFORMATION

Item 1A   *Risk Factors*

If Penn Virginia sells all or a significant part of its remaining partner interests in PVG, our strategic and operational objectives may change.

In September 2009, Penn Virginia sold approximately one-third of its limited partner interest in PVG, constituting approximately 26% of PVG's common units. Following such sale, Penn Virginia continued to own the general partner interest in PVG and approximately 51% of PVG's common units. Penn Virginia may sell all or part of its remaining partner interests in PVG without our or PVG's consent or the consent of our or PVG's unitholders.

Several of the members of our and PVG's management team, including the Chief Executive Officer and Chief Financial Officer of our general partner and PVG's general partner, are also members of Penn Virginia's management team. If Penn Virginia sells all or a significant part of its remaining partner interests in PVG, our general partner and PVG's general partner may replace some or all of those officers with new members of a management team that may have different strategic or operational objectives for us or PVG. A change in strategic or operational objectives could affect our results of operations and cash available for distribution.

Item 6   *Exhibits*

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 5, 2009	By:	/s/ Frank A. Pici Frank A. Pici Vice President and Chief Financial Officer
Date: November 5, 2009	By:	/s/ Forrest W. McNair Forrest W. McNair Vice President and Controller

Exhibit 12.1

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

	Year Ended December 31,					Nine Months Ended
	2004	**2005**	**2006**	**2007**	**2008**	**September 30, 2009**
Earnings						
Pre-tax income *	$ 34,876	$ 52,430	$ 74,910	$ 55,552	$ 103,603	$ 38,932
Fixed charges	7,328	14,351	19,783	19,766	26,850	20,558
Total earnings	**$ 42,204**	**$ 66,781**	**$ 94,693**	**$ 75,318**	**$ 130,453**	**$ 59,490**
Fixed Charges						
Interest expense	$ 7,267	$ 14,053	$ 19,151	$ 18,896	$ 25,346	$ 18,711
Rental interest factor	61	298	632	870	1,504	1,847
Total fixed charges	**$ 7,328**	**$ 14,351**	**$ 19,783**	**$ 19,766**	**$ 26,850**	**$ 20,558**
Ratio of earnings to fixed charges	**5.8x**	**4.7x**	**4.8x**	**3.8x**	**4.9x**	**2.9x**

* Includes cash distributions from equity affiliates and excludes equity earnings from affiliates. Also excludes capitalized interest.

Exhibit 31.1

**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 5, 2009

/s/ A. James Dearlove

A. James Dearlove
Chief Executive Officer

Exhibit 31.2

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 5, 2009

/s/ Frank A. Pici

Frank A. Pici
Vice President and Chief Financial Officer

Exhibit 32.1

**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, 2009, 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 5, 2009

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

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

Exhibit 32.2

CERTIFICATION PURSUANT TO
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, 2009, 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 5, 2009

/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.