
**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 June 30, 2010

or

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

For the transition period from _____ to _____

Commission File Number: 1-16735

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

Delaware
(State or other jurisdiction of
incorporation or organization)

23-3087517
(I.R.S. Employer
Identification No.)

**FOUR RADNOR CORPORATE CENTER, SUITE 200
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 July 20, 2010, 52,293,381 common units representing limited partner interests were outstanding.

PENN VIRGINIA RESOURCE PARTNERS, L.P.

INDEX

	<u>Page</u>
PART I. Financial Information	
Item 1. Financial Statements	
<u>Consolidated Statements of Income for the Three and Six Months Ended June 30, 2010 and 2009</u>	1
<u>Consolidated Balance Sheets as of June 30, 2010 and December 31, 2009</u>	2
<u>Consolidated Statements of Cash Flows for the Three and Six Months Ended June 30, 2010 and 2009</u>	3
<u>Notes to Consolidated Financial Statements</u>	4
<u>Forward-Looking Statements</u>	14
Item 2. <u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	16
Item 3. <u>Quantitative and Qualitative Disclosures About Market Risk</u>	33
Item 4. <u>Controls and Procedures</u>	36
PART II. Other Information	
Item 1A. <u>Risk Factors</u>	37
Item 6. <u>Exhibits</u>	40

PART I. FINANCIAL INFORMATION

Item 1 *Financial Statements*

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

	<u>Three Months Ended</u>		<u>Six Months Ended</u>	
	<u>June 30,</u>		<u>June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Revenues				
Natural gas midstream	\$146,546	\$113,060	\$317,155	\$230,439
Coal royalties	34,879	29,997	63,105	60,627
Coal services	2,028	1,745	4,001	3,633
Other	5,979	4,617	11,649	11,479
Total revenues	<u>189,432</u>	<u>149,419</u>	<u>395,910</u>	<u>306,178</u>
Expenses				
Cost of gas purchased	121,659	92,154	263,454	192,774
Operating	10,261	9,715	20,569	19,460
General and administrative	14,373	8,540	23,184	16,504
Depreciation, depletion and amortization	18,263	17,617	36,081	34,120
Total expenses	<u>164,556</u>	<u>128,026</u>	<u>343,288</u>	<u>262,858</u>
Operating income	24,876	21,393	52,622	43,320
Other income (expense)				
Interest expense	(8,894)	(6,365)	(14,729)	(11,981)
Other	204	328	512	646
Derivatives	7,074	(2,034)	(494)	(9,195)
Net income	<u>\$ 23,260</u>	<u>\$ 13,322</u>	<u>\$ 37,911</u>	<u>\$ 22,790</u>
General partner's interest in net income	<u>\$ 6,437</u>	<u>\$ 6,181</u>	<u>\$ 12,655</u>	<u>\$ 12,285</u>
Limited partners' interest in net income	<u>\$ 16,823</u>	<u>\$ 7,141</u>	<u>\$ 25,256</u>	<u>\$ 10,505</u>
Basic and diluted net income per limited partner unit (see Note 7)	\$ 0.32	\$ 0.13	\$ 0.48	\$ 0.20
Weighted average number of units outstanding, basic and diluted	51,993	51,799	51,923	51,799

The accompanying notes are an integral part of these Consolidated Financial Statements.

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

	June 30, 2010	December 31, 2009
Assets		
Current assets		
Cash and cash equivalents	\$ 15,032	\$ 8,659
Accounts receivable, net of allowance for doubtful accounts	75,026	82,321
Derivative assets	2,488	1,331
Other current assets	4,541	4,468
Total current assets	<u>97,087</u>	<u>96,779</u>
Property, plant and equipment	1,202,239	1,162,070
Accumulated depreciation, depletion and amortization	<u>(288,108)</u>	<u>(261,226)</u>
Net property, plant and equipment	<u>914,131</u>	<u>900,844</u>
Equity investments	85,211	87,601
Intangible assets, net	80,346	83,741
Derivative assets	1,519	1,284
Other long-term assets	<u>43,662</u>	<u>37,811</u>
Total assets	<u>\$1,221,956</u>	<u>\$1,208,060</u>
Liabilities and Partners' Capital		
Current liabilities		
Accounts payable	\$ 57,208	\$ 60,679
Accrued liabilities	16,354	9,726
Deferred income	3,047	3,839
Derivative liabilities	<u>9,320</u>	<u>11,251</u>
Total current liabilities	<u>85,929</u>	<u>85,495</u>
Deferred income	10,502	5,482
Other liabilities	15,597	16,191
Derivative liabilities	4,043	4,285
Senior notes	300,000	—
Revolving credit facility	346,490	620,100
Partners' capital		
Common units (52,293,381 at March 31, 2010 and 51,798,895 at December 31, 2009)	453,162	471,068
General partner interest	6,539	6,834
Accumulated other comprehensive income	<u>(306)</u>	<u>(1,395)</u>
Total partners' capital	<u>459,395</u>	<u>476,507</u>
Total liabilities and partners' capital	<u>\$1,221,956</u>	<u>\$1,208,060</u>

The accompanying notes are an integral part of these Consolidated Financial Statements.

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2010	2009	2010	2009
Cash flows from operating activities				
Net income	\$ 23,260	\$ 13,322	\$ 37,911	\$ 22,790
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	18,263	17,617	36,081	34,120
Commodity derivative contracts:				
Total derivative (gains) losses	(6,566)	2,951	1,584	10,566
Cash receipts (payments) to settle derivatives	(2,412)	1,613	(4,058)	4,449
Non-cash interest expense	1,367	1,242	2,610	1,733
Non-cash unit-based compensation	4,952	—	5,887	—
Equity earnings, net of distributions received	1,947	488	2,390	(1,071)
Other	(312)	(335)	(612)	(630)
Changes in operating assets and liabilities:				
Accounts receivable	1,426	(2,021)	10,930	14,038
Accounts payable	(508)	(2,894)	(4,486)	(13,387)
Accrued liabilities	5,583	4,546	4,627	3,417
Deferred income	767	(783)	728	(2,343)
Other asset and liabilities	(4,550)	3,439	(773)	(124)
Net cash provided by operating activities	<u>43,217</u>	<u>39,185</u>	<u>92,819</u>	<u>73,558</u>
Cash flows from investing activities				
Acquisitions	(17,835)	(606)	(17,864)	(1,862)
Additions to property, plant and equipment	(16,776)	(15,208)	(24,733)	(32,258)
Other	398	307	670	572
Net cash used in investing activities	<u>(34,213)</u>	<u>(15,507)</u>	<u>(41,927)</u>	<u>(33,548)</u>
Cash flows from financing activities				
Distributions to partners	(31,142)	(30,878)	(62,184)	(61,755)
Proceeds from issuance of senior notes	300,000	—	300,000	—
Proceeds from borrowings	56,000	14,000	66,000	41,000
Repayments of borrowings	(327,610)	(12,000)	(339,610)	(12,000)
Net proceeds from issuance of partners' capital	—	—	22	—
Debt issuance costs	(8,747)	—	(8,747)	(9,258)
Net cash used in financing activities	<u>(11,499)</u>	<u>(28,878)</u>	<u>(44,519)</u>	<u>(42,013)</u>
Net increase (decrease) in cash and cash equivalents	(2,495)	(5,200)	6,373	(2,003)
Cash and cash equivalents – beginning of period	17,527	12,681	8,659	9,484
Cash and cash equivalents – end of period	<u>\$ 15,032</u>	<u>\$ 7,481</u>	<u>\$ 15,032</u>	<u>\$ 7,481</u>
Supplemental disclosure:				
Cash paid for interest	\$ 4,967	\$ 5,846	\$ 11,396	\$ 12,002

The accompanying notes are an integral part of these Consolidated Financial Statements.

PENN VIRGINIA RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – unaudited
June 30, 2010

1. Organization

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

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

Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. We own and operate natural gas midstream assets located in Oklahoma and Texas. Our natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. In addition, we own a 25% member interest in Thunder Creek Gas Services, LLC (“Thunder Creek”), a joint venture that gathers and transports coalbed methane in Wyoming’s Powder River Basin. We also own a 50% percent member interest in Crosspoint Pipeline LLC (“Crosspoint”), a joint venture that gathers and transports natural gas from our Crossroads gas processing plant to an interstate pipeline. We own a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

Our general partner is Penn Virginia Resource GP, LLC, which is a wholly owned subsidiary of Penn Virginia GP Holdings, L.P. (“PVG”), a publicly traded Delaware limited partnership. Effective June 7, 2010, Penn Virginia Corporation (“PVA”) completed its divestiture of PVG and as a result, PVA no longer owns any limited or general partner interests in us or PVG. At June 30, 2010, 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 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 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 Consolidated Financial Statements have been included. Our 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, 2009. Operating results for the three and six months ended June 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010.

Management has evaluated all activities of the Partnership through the date upon which our Consolidated Financial Statements were issued and concluded that no subsequent events have occurred that would require recognition in the Consolidated Financial Statements or disclosure in these Notes.

Certain reclassifications have been made to conform to the current period’s presentation of taxes other than income. Historically, we reported taxes other than income as a separate component of expenses. We have reclassified the components of taxes other than income, which primarily related to property taxes and payroll taxes, to operating expense and general and administrative expense for all periods presented.

All dollar amounts presented in the tables to these Notes are in thousands unless otherwise indicated.

3. Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. 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, 2009.

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and long-term debt. At June 30, 2010, the carrying values of all of these financial instruments, except the long-term debt with fixed interest rates, approximated fair value. The fair value of floating-rate debt approximates the carrying amount because the interest rates paid are based on short-term maturities. The fair value of our fixed-rate long-term debt is estimated based on the published market prices for the same or similar issues. As of June 30, 2010, the fair value of our fixed-rate debt was \$294.0 million.

Recurring Fair Value Measurements

Certain assets and liabilities, including our derivatives, are measured at fair value on a recurring basis in our Consolidated Balance Sheet. The following tables summarize the valuation of our assets and liabilities for the periods presented:

Description	Fair Value Measurements at June 30, 2010	Fair Value Measurements at June 30, 2010, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Interest rate swap liabilities - current	\$ (6,924)	—	\$ (6,924)	—
Interest rate swap liabilities - noncurrent	(3,514)	—	(3,514)	—
Commodity derivative assets - current	2,488	—	2,488	—
Commodity derivative assets - noncurrent	1,519	—	1,519	—
Commodity derivative liabilities - current	(2,396)	—	(2,396)	—
Commodity derivative liabilities - noncurrent	(529)	—	(529)	—
Total	\$ (9,356)	\$ —	\$ (9,356)	\$ —

Description	Fair Value Measurements at December 31, 2009	Fair Value Measurements at December 31, 2009, Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Interest rate swap assets - noncurrent	\$ 1,266	\$ —	\$ 1,266	\$ —
Interest rate swap liabilities - current	(7,710)	—	(7,710)	—
Interest rate swap liabilities - noncurrent	(3,241)	—	(3,241)	—
Commodity derivative assets - current	1,331	—	1,331	—
Commodity derivative assets - noncurrent	18	—	18	—
Commodity derivative liabilities - current	(3,541)	—	(3,541)	—
Commodity derivative liabilities - noncurrent	(1,044)	—	(1,044)	—
Total	\$ (12,921)	\$ —	\$ (12,921)	\$ —

We used the following methods and assumptions to estimate the fair values:

- *Commodity derivative:* We utilize costless collars and swap derivative contracts to hedge against the variability in the fractionation, or frac, spread. We determine the fair values of our commodity derivative agreements based on discounted cash flows based on quoted forward prices for the respective commodities. Each of these is a level 2 input. We use the income approach, using valuation techniques that convert future cash flows to a single discounted value. See Note 4 for the effects of the derivative instruments on our Consolidated Statements of Income.
- *Interest rate swaps:* We have entered into the interest rate swaps (“Interest Rate Swaps”) to

establish fixed rates on a portion of the outstanding borrowings under the revolving credit facility (“Revolver”). We use an income approach using valuation techniques that connect future cash flows to a single discounted value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these is a level 2 input.

4. Derivative Instruments

Natural Gas Midstream Segment Commodity Derivatives

We determine the fair values of our derivative agreements using third-party 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 commodity derivative positions as of June 30, 2010:

	Average Volume Per Day	Swap Price	Weighted Average Price		Fair Value at June 30, 2010 (in thousands)
			Put	Call	
Crude oil collar	(barrels)		(per barrel)		
Third quarter 2010 through fourth quarter 2010	750		\$ 70.00	\$ 81.25	\$ (89)
Crude oil collar	(barrels)		(per barrel)		
Third quarter 2010 through fourth quarter 2010	1,000		\$ 68.00	\$ 80.00	\$ (289)
Natural gas purchase swap	(MMBtu)	(MMBtu)			
Third quarter 2010 through fourth quarter 2010	7,100	\$ 5.885			\$ (1,378)
NGL - natural gasoline collar	(gallons)		(per gallon)		
Third quarter 2010 through fourth quarter 2010	42,000		\$ 1.55	\$ 2.03	\$ 435
NGL - natural gasoline collar	(gallons)		(per gallon)		
First quarter 2011 through fourth quarter 2011	95,000		\$ 1.57	\$ 1.94	\$ 2,374
Crude oil collar	(barrels)		(per barrel)		
First quarter 2011 through fourth quarter 2011	400		\$ 75.00	\$ 98.50	\$ 629
Natural gas purchase swap	(MMBtu)	(MMBtu)			
First quarter 2011 through fourth quarter 2011	6,500	\$ 5.796			\$ (1,053)
Settlements to be received in subsequent period					\$ 453

Interest Rate Swaps

We have entered into the Interest Rate Swaps to establish fixed interest rates on a portion of the outstanding borrowings under the Revolver. The following table sets forth the positions of the Interest Rate Swaps for the periods presented:

Term	Notional Amounts (in millions)	Swap Interest Rates (1)		Fair Value June 30, 2010
		Pay	Receive	
March 2010 - December 2011	\$ 250.0	3.37%	LIBOR	\$ (9,939)
December 2011 - December 2012	\$ 100.0	2.09%	LIBOR	\$ (498)

(1) References to LIBOR represent the 3-month rate.

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 caption on our Consolidated Statements of Income. As of June 30, 2010, a \$0.3 million loss remained in

accumulated other comprehensive income (“AOCI”) related to the Interest Rate Swaps. The \$0.3 million loss will be recognized in interest expense when the original forecasted transactions occur.

We reported a (i) net derivative liability of \$10.4 million at June 30, 2010 and (ii) loss in AOCI of \$0.3 million as of June 30, 2010 related to the Interest Rate Swaps. In connection with periodic settlements, we reclassified a total of \$1.1 million of net hedging losses on the Interest Rate Swaps from AOCI to interest expense during the six months ended June 30, 2010. See the “Financial Statement Impact of Derivatives” section below for the impact of the Interest Rate Swaps on our 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 Consolidated Statements of Income for the periods presented:

	Location of gain (loss) on derivatives recognized in income	Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives not designated as hedging instruments:					
Interest rate contracts (1)	Interest expense	(508)	(918)	(1,090)	(1,743)
Interest rate contracts	Derivatives	(2,041)	1,810	(5,171)	696
Commodity contracts	Derivatives	9,115	(3,843)	4,677	(9,890)
Total increase (decrease) in net income resulting from derivatives		\$ 6,566	\$ (2,951)	\$ (1,584)	\$ (10,937)
Realized and unrealized derivative impact:					
Cash received (paid) for commodity and interest rate contract settlements	Derivatives	(2,412)	1,613	(4,058)	4,449
Cash paid for interest rate contract settlements	Interest expense	—	—	—	(370)
Unrealized derivative (gains) losses (2)		8,978	(4,564)	2,474	(15,016)
Total increase (decrease) in net income resulting from derivatives		\$ 6,566	\$ (2,951)	\$ (1,584)	\$ (10,937)

- (1) This represents Interest Rate Swap amounts reclassified out of AOCI and into earnings. By the first quarter of 2009, we discontinued cash flow hedge accounting for all Interest Rate Swaps.
- (2) This activity represents unrealized losses in the interest expense and derivatives caption on our Consolidated Statements of Income.

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments, on our Consolidated Balance Sheets for the periods presented:

Balance Sheet Location	Fair values as of June 30, 2010		Fair values as of December 31, 2009		
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities	
Derivatives not designated as hedging instruments:					
Interest rate contracts	Derivative assets/liabilities - current	\$ —	\$ 6,924	\$ —	\$ 7,710
Interest rate contracts	Derivative assets/liabilities - noncurrent	—	3,513	1,266	3,241
Commodity contracts	Derivative assets/liabilities - current	2,488	2,396	1,331	3,541
Commodity contracts	Derivative assets/liabilities - noncurrent	1,519	529	18	1,044
Total derivatives not designated as hedging instruments		\$ 4,007	\$ 13,362	\$ 2,615	\$ 15,536

See Note 3 for a description of how the above-described financial instruments are valued.

As of June 30, 2010, we did not own derivative instruments that were classified as fair value hedges or trading securities. In addition, as of June 30, 2010, we did not own derivative instruments containing credit risk contingencies.

5. Equity Investments

In accordance with the equity method of accounting, we recognized earnings of \$4.4 million and \$2.6 million for the six months ended June 30, 2010 and 2009, with a corresponding increase in the investment. The joint ventures generally pay quarterly distributions on their cash flow. We received distributions of \$6.7 million and \$1.5 million for the six months ended June 30, 2010 and 2009. Equity earnings related to our 50% interest in Coal Handling Solutions LLC are included in coal services revenues, and

equity earnings related to our 25% interest in Thunder Creek and our 50% interest in Crosspoint are recorded in other revenues on the Consolidated Statements of Income. The equity investments for all joint ventures are included in the equity investments caption on the Consolidated Balance Sheets.

Summarized financial information of unconsolidated equity investments is as follows for the periods presented:

	<u>June 30,</u> <u>2010</u>	<u>December 31,</u> <u>2009</u>
Current assets	\$ 37,701	\$ 32,996
Noncurrent assets	\$209,067	\$ 214,463
Current liabilities	\$ 7,390	\$ 4,898
Noncurrent liabilities	\$ 5,505	\$ 5,392
	<u>Six Months Ended June 30,</u> <u>2010</u>	<u>2009</u>
Revenues	\$ 35,122	\$ 29,257
Expenses	\$ 17,107	\$ 17,563
Net income	\$ 18,015	\$ 11,694

6. Long-term Debt

Senior Notes

In April 2010, we sold \$300.0 million of unsecured senior notes due on April 15, 2018 (the “Senior Notes”) with an annual interest rate of 8.25%, which is payable semi-annually in arrears on April 15 and October 15 of each year. The Senior Notes were sold at par, equating to an effective yield to maturity of approximately 8.25%. The net proceeds from the sale of the Senior Notes of approximately \$292.6 million, after deducting underwriter fees and expenses of approximately \$7.4 million, were used to repay borrowings under the Revolver. We may redeem some or all of the Senior Notes at any time on or after April 15, 2014 at the redemption prices set forth in the indenture governing the Senior Notes and prior to such date at a “make-whole” redemption price. We may also redeem up to 35% of the Senior Notes prior to April 15, 2013 with cash proceeds received from certain equity offerings. If we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if we experience a change of control, we must offer to repurchase the Senior Notes. The Senior Notes are senior to any subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including our indebtedness under the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by our current and future subsidiaries, which are also guarantors under the Revolver.

Revolver

Effective June 7, 2010, PVA completed its divestiture of PVG and as a result, PVA no longer owns any limited or general partner interests in us or PVG. Immediately prior to this divestiture, we amended the Revolver to amend the definition of “Change of Control” thereunder, with the effect that the sale by PVA of its remaining beneficial ownership of common units would not constitute a change of control of us. The amendment of the Revolver also amended the negative covenant restricting the incurrence of indebtedness, with the effect that we may issue an additional \$300.0 million of unsecured senior or subordinated notes, in addition to the Senior Notes.

7. Partners’ Capital and Distributions

As of June 30, 2010, partners’ capital consisted of 52.3 million common units, representing a 98% limited partner interest, and a 2% general partner interest. As of June 30, 2010, PVG owned an approximate 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

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 six months ended June 30, 2010, average awards of 137,000 and 187,000 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. For the three and six months ended June 30, 2009, average awards of 88,000 and 75,000 were excluded.

The following table reconciles the computation of net income to net income allocable to limited partners:

	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Net income	\$ 23,260	\$ 13,322	\$ 37,911	\$ 22,790
Adjustments:				
Distributions payable on account of incentive distribution rights	(6,093)	(6,035)	(12,139)	(12,070)
Distributions payable on account of general partner interest	(502)	(497)	(1,000)	(994)
General partner interest in excess of distributions over earnings allocable to the general partner interest	158	351	484	779
Net income allocable to limited partners and participating securities	\$ 16,823	\$ 7,141	\$ 25,256	\$ 10,505
Adjustments:				
Distributions to participating securities	(164)	(167)	(343)	(334)
Participating securities' allocable share of net income	53	(47)	168	(69)
Net income allocable to limited partners	\$ 16,712	\$ 6,927	\$ 25,081	\$ 10,102
Weighted average limited partner units, basic and diluted	51,993	51,799	51,923	51,799
Net income per limited partner unit, basic and diluted	\$ 0.32	\$ 0.13	\$ 0.48	\$ 0.20

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.

The following table reflects the allocation of total cash distributions paid by us during the periods presented:

	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Limited partner units	\$ 24,390	\$ 24,346	\$ 48,735	\$ 48,691
General partner interest (2%)	498	497	995	994
Incentive distribution rights	6,046	6,035	12,081	12,070
Phantom units	208	—	373	—
Total cash distributions paid	\$ 31,142	\$ 30,878	\$ 62,184	\$ 61,755
Total cash distributions paid per limited partner unit	\$ 0.47	\$ 0.47	\$ 0.94	\$ 0.94

On August 13, 2010, we will pay a \$0.47 per unit quarterly distribution to unitholders of record on August 6, 2010. This per unit distribution remains unchanged from the previous distribution paid on May 14, 2010.

8. Related-Party Transactions

In June 2010, PVA sold its remaining interest in PVG and as a result, PVA no longer owns any limited or general partner interests in us or PVG. As a result of the divestiture, the related party transactions noted below will now be considered arm's-length and will no longer require separate disclosures. PVR and PVG executed a transition agreement with PVA covering the services of certain shared employees, aiding the transition of corporate and accounting functions that will continue until March 2011. The transition agreement with PVA was approved by the Conflicts Committee of both PVR and PVG. Related party transactions included charges from Penn Virginia for certain corporate administrative expenses which are allocable to us and our subsidiaries. Other transactions involved subsidiaries of PVA related to the marketing of natural gas, gathering and processing of natural gas, and the purchase and sale of natural gas and NGLs in which we took title to the products. The income statement and balance sheet amounts noted below represent related party transactions through June 7, 2010 (date of divestiture). Future periodic disclosure of amounts will be historical in nature.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Statement of Income:				
Natural gas midstream revenues	\$ 10,099	\$ 21,246	\$ 29,002	\$ 43,364
Other income	\$ 373	\$ 370	\$ 787	\$ 771
Cost of gas purchased	\$ 9,586	\$ 20,062	\$ 27,780	\$ 41,229
General and administrative	\$ 552	\$ 1,550	\$ 1,773	\$ 3,100
Balance Sheet:				
Accounts receivable	\$ —	\$ 674		
Accounts payable	\$ —	\$ 7,889		

9. 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. 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 generally 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 caption on our Consolidated Statements of Income. In 2010, we granted 230,319 phantom units at a weighted average grant-date fair value of \$22.86.

Because PVA's divestiture of PVG was considered a change of control under the LTIP, all unvested restricted and phantom units granted to employees performing services for the benefit of us were considered vested on the date of the divestiture. In total, 400,090 phantom units vested and an equal number of new common units were issued on that date. The restrictions on approximately 36,000 restricted units were also lifted. In connection with the normal three-year vesting and this accelerated vesting of phantom units, we recognized non-cash compensation expense of \$5.0 million and \$5.9 million for the three and six months ended June 30, 2010. In connection with the normal three-year vesting and this accelerated vesting of restricted units, we recognized compensation expense of \$0.8 million and \$1.2 million for the three and six months ended June 30, 2010. We also recognized a total of \$0.1 million and \$0.2 million compensation expense for the three and six months ended June 30, 2010 and 2009 related to the granting of deferred common units under our LTIP. Compensation expense of \$1.3 million and \$2.7 million was recognized for the three and six months ended June 30, 2009 related to the vesting of restricted, phantom and deferred common units under our LTIP.

10. 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 periods presented:

	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Net income	\$ 23,260	\$ 13,322	\$ 37,911	\$ 22,790
Unrealized holding losses on derivative activities	—	—	—	(506)
Reclassification adjustment for derivative activities	508	918	1,090	1,743
Comprehensive income	<u>\$ 23,768</u>	<u>\$ 14,240</u>	<u>\$ 39,001</u>	<u>\$ 24,027</u>

11. 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 June 30, 2010 and December 31, 2009, our environmental liabilities were \$0.9 million and \$1.0 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 six months ended June 30, 2010, two of our natural gas midstream segment customers accounted for \$55.1 million and \$41.0 million, or 14% and 10%, of our total consolidated revenues. At June 30, 2010, 21% of our consolidated accounts receivable related to these customers.

12. Segment Information

Our reportable segments are as follows:

- *Coal and Natural Resource Management* — Our coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities and collecting oil and gas royalties.
- *Natural Gas Midstream* — Our natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. In addition, we own member interests in joint ventures that gather and transport natural gas.

The following tables present a summary of certain financial information relating to our segments for the periods presented:

	Revenues		Operating income	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2010	2009	2010	2009
Coal and natural resource management	\$ 40,582	\$ 35,144	\$ 24,781	\$ 20,333
Natural gas midstream	148,850	114,275	95	1,060
Consolidated totals	\$ 189,432	\$ 149,419	\$ 24,876	\$ 21,393
Interest expense			(8,894)	(6,365)
Other			204	328
Derivatives			7,074	(2,034)
Consolidated net income			\$ 23,260	\$ 13,322

	Additions to property and equipment		DD&A expense	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2010	2009	2010	2009
Coal and natural resource management	\$ 18,082	\$ 606	\$ 7,379	\$ 8,164
Natural gas midstream	16,529	15,208	10,884	9,453
Consolidated totals	\$ 34,611	\$ 15,814	\$ 18,263	\$ 17,617

	Revenues		Operating income	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Coal and natural resource management	\$ 74,142	\$ 73,396	\$ 45,142	\$ 45,307
Natural gas midstream	321,768	232,782	7,480	(1,987)
Consolidated totals	\$ 395,910	\$ 306,178	\$ 52,622	\$ 43,320
Interest expense			(14,729)	(11,981)
Other			512	646
Derivatives			(494)	(9,195)
Consolidated net income			\$ 37,911	\$ 22,790

	Additions to property and equipment		DD&A expense	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Coal and natural resource management	\$ 18,114	\$ 1,906	\$ 14,705	\$ 15,558
Natural gas midstream	24,483	32,214	21,376	18,562
Consolidated totals	\$ 42,597	\$ 34,120	\$ 36,081	\$ 34,120

	Total assets at	
	June 30,	December 31,
	2010	2009
Coal and natural resource management	\$ 591,088	\$ 574,258
Natural gas midstream	630,868	633,802
Consolidated totals	\$1,221,956	\$1,208,060

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, or Exchange Act. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- the volatility of commodity prices for natural gas, natural gas liquids, or 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, 2009.

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, 2009. 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 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 Consolidated Financial Statements and Notes thereto in Item 1. All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated.

Overview of Business

We are a publicly traded Delaware limited partnership formed by Penn Virginia Corporation, or PVA, 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.

Key Developments

During the three months ended June 30, 2010, the following general business developments and corporate actions had an impact, or will have impact, on the financial reporting of our results of operations. A discussion of these key developments follows:

2010 Commodity Prices

Coal royalties, which accounted for 86% of the coal and natural resource management segment revenues for the three months ended June 30, 2010 and 85% for the same period in 2009, were higher as compared to 2009. The increase was attributed to increased production and higher realized coal royalty per ton by region. We continue to benefit from long-term contract prices our lessees previously negotiated with their customers. However, the state of the global economy, including financial and credit markets, has reduced worldwide demand for coal with resultant price declines. Depending on the longevity of the market deterioration, demand for coal may continue to decline, which could adversely affect production and pricing for coal mined by our lessees.

The average commodity prices for natural gas, crude oil and natural gas liquids, or NGLs, for the second quarter of 2010 fell back from levels experienced in the first quarter of 2010. However, the prices increased for the three months ended June 30, 2010 compared to the same period of 2009. NGLs refer to ethane, propane, iso butane, normal butane and pentane. The pricing of these commodities directly and indirectly drive our earnings.

Revenues, profitability and the future rate of growth of our natural gas midstream segment are highly dependent on market demand and prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have generally correlated with changes in the price of crude oil. NGL and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market demand. As part of our risk management strategy, we use derivative financial instruments to economically hedge NGLs sold and natural gas purchased. Our derivative financial instruments include costless collars and swaps. Based upon current volumes, we have entered into hedging arrangements covering approximately 60% and 58% of our commodity-sensitive volumes in 2010 and 2011. We generally target hedging 50% to 60% of our commodity-sensitive volumes covering a two-year period.

PVR Midstream Marcellus Shale Construction

Construction efforts continue in Pennsylvania as we work towards building and operating gas gathering pipelines and compression facilities servicing natural gas producers in the Marcellus Shale development. The Wyoming County project became operational during June, while projects targeting parts of Lycoming, Tioga and Bradford Counties in north central Pennsylvania have moved forward.

Senior Notes Offering

In April 2010, the Company sold \$300.0 million of unsecured senior notes due on April 15, 2018, or the Senior Notes, with an annual interest rate of 8.25% which is payable semi-annually in arrears on April 15 and October 15 of each year. The Senior Notes were sold at par, equating to an effective yield to maturity of approximately 8.25%.

The net proceeds from the sale of the Senior Notes of approximately \$292.6 million, after deducting fees and expenses of approximately \$7.4 million, were used to repay borrowings under our revolving credit facility, or the Revolver.

Liquidity and Capital Resources

Cash Flows

On an ongoing basis, we generally satisfy our working capital requirements and fund our capital expenditures using cash generated from our operations, borrowings under the Revolver and proceeds from equity offerings. As discussed in more detail in “— Sources of Liquidity” below, as of June 30, 2010, we had availability of \$451.9 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), scheduled debt payments and distributions. 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.

The following table summarizes our cash flow statements for the periods presented:

	<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>
Cash flows from operating activities:		
Net income	\$ 37,911	\$ 22,790
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	43,882	49,167
Net changes in operating assets and liabilities	<u>11,026</u>	<u>1,601</u>
Net cash provided by operating activities	92,819	73,558
Net cash used in investing activities	(41,927)	(33,548)
Net cash used in financing activities	<u>(44,519)</u>	<u>(42,013)</u>
Net increase (decrease) in cash and cash equivalents	<u>\$ 6,373</u>	<u>\$ (2,003)</u>

Cash Flows From Operating Activities

The overall increase in net cash provided by operating activities in the six months ended June 30, 2010 as compared to the same period in 2009 was driven by an increase in the natural gas midstream segment’s gross margin. Higher commodity prices for natural gas as well as NGLs increased our margins even though lower throughput volumes were experienced for the comparative periods.

Cash Flows From Investing Activities

Net cash used in investing activities were primarily for capital expenditures. The following table sets forth our capital expenditures program, by segment, for the periods presented:

	<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>
Coal and natural resource management		
Acquisitions	\$ 17,864	\$ 1,862
Other property and equipment expenditures	250	47
Total	<u>18,114</u>	<u>1,909</u>
Natural gas midstream		
Expansion capital expenditures	22,027	21,544
Other property and equipment expenditures	5,861	4,636
Total	<u>27,888</u>	<u>26,180</u>
Total capital expenditures	<u>\$ 46,002</u>	<u>\$ 28,089</u>

Our capital expenditures for the six months ended June 30, 2010 and 2009 consisted primarily of natural gas midstream expansion capital used to increase our operational footprint in our Panhandle and Marcellus Shale Systems. The coal and natural resource management segment acquired 10 million tons of coal in northern Appalachia for \$17.7 million.

Cash Flows From Financing Activities

During the six months ended June 30, 2010, we incurred \$8.7 million of debt issuance costs related to the issuance of the \$300 million Senior Notes. The net borrowings during both the six months ended June 30, 2010 and 2009 were used to finance acquisition and expansion projects.

Certain Non-GAAP Financial Measures

We use non-GAAP measures to evaluate our business and performance. None of these measures should be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, or as indicators of our operating performance or liquidity.

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2010	2009	2010	2009
Reconciliation of GAAP "Net income" to Non-GAAP "Distributable cash flow"				
Net income	\$23,260	\$13,322	\$37,911	\$22,790
Depreciation, depletion and amortization	18,263	17,617	36,081	34,120
Commodity derivative contracts:				
Derivative (gains) losses included in net income	(6,566)	2,951	1,584	10,566
Cash receipts (payments) to settle derivatives for the period	(2,412)	1,613	(4,058)	4,449
Equity earnings from joint venture, net of distributions	1,947	488	2,390	(1,071)
Maintenance capital expenditures	(4,254)	(1,354)	(6,111)	(4,636)
Distributable cash flow (a)	<u>\$30,238</u>	<u>\$34,637</u>	<u>\$67,797</u>	<u>\$66,218</u>

Note: Includes a non-cash charge of \$5.0 million of one-time equity vesting expenses incurred in the second quarter of 2010 upon the change of control of PVR from Penn Virginia Corporation.

Distribution to Partners:

Limited partner units	\$24,390	\$24,345	\$48,735	\$48,691
Phantom units (b)	208	—	373	—
General partner interest	498	497	995	994
Incentive distribution rights (c)	6,046	6,035	12,081	12,070
Total cash distribution paid during period	<u>\$31,142</u>	<u>\$30,877</u>	<u>\$62,184</u>	<u>\$61,755</u>
Total cash distribution paid per unit during period	<u>\$ 0.47</u>	<u>\$ 0.47</u>	<u>\$ 0.94</u>	<u>\$ 0.94</u>

Reconciliation of GAAP "Net income" to Non-GAAP "Net income as adjusted"

Net income	\$23,260	\$13,322	\$37,911	\$22,790
Adjustments for derivatives:				
Derivative (gains) losses included in net income	(6,566)	2,951	1,584	10,566
Cash receipts (payments) to settle derivatives for the period	(2,412)	1,613	(4,058)	4,449
Net income, as adjusted (d)	<u>\$14,282</u>	<u>\$17,886</u>	<u>\$35,437</u>	<u>\$37,805</u>
Allocation of net income, as adjusted:				
General partner's interest in net income, as adjusted	\$ 6,257	\$ 6,272	\$12,606	\$12,585
Limited partners' interest in net income, as adjusted	\$ 8,025	\$11,614	\$22,831	\$25,220
Net income, as adjusted, per limited partner unit, basic and diluted	<u>\$ 0.15</u>	<u>\$ 0.22</u>	<u>\$ 0.44</u>	<u>\$ 0.48</u>

(a) Distributable cash flow represents net income plus DD&A expenses, plus (minus) derivative losses (gains) included in operating income and other income, plus (minus) cash received (paid) for derivative settlements, minus equity earnings in joint ventures, plus cash distributions from joint ventures, minus other capital expenditures. Distributable cash flow is a significant liquidity metric which is an indicator of our ability to generate cash flows at a level that can sustain or support an increase in quarterly cash distributions paid to our partners. Distributable cash flow is also the quantitative standard used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of publicly traded partnerships. Distributable cash flow is presented because we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or

- financing activities, as an indicator of cash flows, as a measure of liquidity or as an alternative to net income.
- (b) Phantom unit grants were made in 2010 and 2009 under our long-term incentive plan. Phantom units receive distribution rights; thus, we have presented distributions paid to phantom unit holders in our total distributions paid to partners.
 - (c) In accordance with our partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved.
 - (d) Net income, as adjusted, represents net income adjusted to include the cash effects of derivative cash settlements and exclude the effects of non-cash changes in the fair value of derivatives. We believe this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies in the natural gas midstream industry. We use this information for comparative purposes within the industry. Net income, as adjusted, is not a measure of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net income.

Distributable cash flow for the second quarter of 2010 of \$30.2 million was \$4.4 million, or 13 percent lower, than the \$34.6 million of distributable cash flow in the second quarter of 2009 primarily due to:

- \$5.7 million increase in general and administrative costs associated with the accelerated vesting of equity compensation triggered by the change of control;
- \$2.9 million increase in maintenance capital; and
- \$2.5 million increase in interest expense associated with the higher interest bearing Senior Notes.

These decreases in distributable cash flow were partially offset by:

- \$5.4 million increase in coal and natural resource management segment total revenues due to increased average coal royalties per ton.

Sources of Liquidity

Long-Term Debt

Revolver. As of June 30, 2010, net of outstanding borrowings of \$346.5 million and letters of credit of \$1.6 million, we had remaining borrowing capacity of \$451.9 million on the Revolver. 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. The interest rate under the Revolver fluctuates based on the ratio of our total indebtedness-to-EBITDA. Interest is payable at a base rate plus an applicable margin of up to 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. The weighted average interest rate on borrowings outstanding under the Revolver during the six months ended June 30, 2010 was approximately 2.3%. We do not have a public rating for the Revolver. As of June 30, 2010, we were in compliance with all of our covenants under the Revolver.

Interest Rate Swaps. We have entered into interest rate swaps, or the Interest Rate Swaps, to establish fixed rates on a portion of the outstanding borrowings under the Revolver. The following table sets forth the Interest Rate Swap positions as of June 30, 2010:

Term	Notional Amounts (in millions)	Swap Interest Rates (1)	
		Pay	Receive
March 2010 - December 2011	\$ 250.0	3.37%	LIBOR
December 2011 - December 2012	\$ 100.0	2.09%	LIBOR

(1) References to LIBOR represent the 3-month rate.

The Interest Rate Swaps extend one year past the maturity of the current Revolver. After considering the applicable margin of 2.00% in effect as of June 30, 2010 the total interest rate on the \$250.0 million portion of the Revolver borrowings covered by the Interest Rate Swaps was 5.37% as of June 30, 2010.

Senior Notes. In April 2010, we sold \$300.0 million of Senior Notes due on April 15, 2018 with an annual interest rate of 8.25%, which is payable semi-annually in arrears on April 15 and October 15 of each year. The Senior Notes were sold at par, equating to an effective yield to maturity of approximately 8.25%. The net proceeds from the sale of the Senior Notes of approximately \$292.6 million, after deducting fees and expenses of approximately \$7.4 million, were used to repay borrowings under the Revolver. We may redeem some or all of the Senior Notes at any time on or after April 15, 2014 at the redemption prices set forth in the Supplemental Indenture governing the Senior Notes and prior to such date at a “make-whole” redemption price. We may also redeem up to 35% of the Senior Notes prior to April 15, 2013 with cash proceeds received from certain equity offerings. If we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if we experience a change of control, we must offer to repurchase the Senior Notes. The Senior Notes are senior to any subordinated indebtedness, and are effectively subordinated to all of our secured indebtedness including the Revolver to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by our current and future subsidiaries, which are also guarantors under the Revolver.

Future Capital Needs and Commitments

As of June 30, 2010, our remaining borrowing capacity under the Revolver of approximately \$451.9 million will be more than sufficient to meet our anticipated 2010 capital needs and commitments. Our short-term cash requirements for operating expenses and quarterly distributions to our general partner and our unitholders are expected to be funded through operating cash flows. In 2010, we anticipate making capital expenditures, excluding acquisitions, of approximately \$142.0 million, including anticipated maintenance capital of \$17.0 million to \$22.0 million. The majority of the 2010 capital expenditures are expected to be incurred in the natural gas midstream segment. We intend to fund these capital expenditures with a combination of operating cash flows and borrowings under the Revolver. Long-term cash requirements for acquisitions and other capital expenditures are expected to be funded by operating cash flows, borrowings under the Revolver and the issuances of additional debt and equity securities if available under commercially acceptable terms.

Part of our long-term strategy is to increase cash available for distribution to our unitholders by making acquisitions and other capital expenditures. Our ability to make these acquisitions and other capital expenditures in the future will depend largely on the availability of debt financing and on our ability to periodically use equity financing through the issuance of new common units. Future financing will depend on various factors, including prevailing market conditions, interest rates and our financial condition and credit rating.

Results of Operations

Consolidated Review

The following table presents summary consolidated results for the periods presented:

	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Revenues	\$ 189,432	\$ 149,419	\$ 395,910	\$ 306,178
Expenses	164,556	128,026	343,288	262,858
Operating income	24,876	21,393	52,622	43,320
Other income (expense)	(1,616)	(8,071)	(14,711)	(20,530)
Net income	\$ 23,260	\$ 13,322	\$ 37,911	\$ 22,790

The following table presents a summary of certain financial information relating to our segments for the periods presented:

	<u>Coal and Natural Resource Management</u>	<u>Natural Gas Midstream</u>	<u>Consolidated</u>
For the Six Months Ended June 30, 2010:			
Revenues	\$ 74,142	\$ 321,768	\$ 395,910
Cost of gas purchased	—	(263,454)	(263,454)
Operating costs and expenses	(14,295)	(29,458)	(43,753)
Depreciation, depletion and amortization	(14,705)	(21,376)	(36,081)
Operating income	<u>\$ 45,142</u>	<u>\$ 7,480</u>	<u>\$ 52,622</u>
For the Six Months Ended June 30, 2009:			
Revenues	\$ 73,396	\$ 232,782	\$ 306,178
Cost of gas purchased	—	(192,774)	(192,774)
Operating costs and expenses	(12,531)	(23,433)	(35,964)
Depreciation, depletion and amortization	(15,558)	(18,562)	(34,120)
Operating income (loss)	<u>\$ 45,307</u>	<u>\$ (1,987)</u>	<u>\$ 43,320</u>

Coal and Natural Resource Management Segment

Three Months Ended June 30, 2010 Compared with Three Months Ended June 30, 2009

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

	Three Months Ended June 30,		Favorable (Unfavorable)	% Change
	2010	2009		
Financial Highlights				
Revenues				
Coal royalties	\$ 34,879	\$ 29,997	\$ 4,882	16%
Coal services	2,028	1,745	283	16%
Timber	1,746	1,456	290	20%
Oil and gas royalty	625	545	80	15%
Other	1,304	1,401	(97)	(7%)
Total revenues	<u>40,582</u>	<u>35,144</u>	<u>5,438</u>	15%
Expenses				
Coal royalties	1,630	1,569	(61)	(4%)
Other operating	951	919	(32)	(3%)
General and administrative	5,841	4,159	(1,682)	(40%)
Depreciation, depletion and amortization	7,379	8,164	785	10%
Total expenses	<u>15,801</u>	<u>14,811</u>	<u>(990)</u>	(7%)
Operating income	<u>\$ 24,781</u>	<u>\$ 20,333</u>	<u>\$ 4,448</u>	22%
Other data				
Coal royalty tons by region				
Central Appalachia	5,012	4,650	362	8%
Northern Appalachia	1,069	1,060	9	1%
Illinois Basin	1,107	1,145	(38)	(3%)
San Juan Basin	1,684	1,884	(200)	(11%)
Total	<u>8,872</u>	<u>8,739</u>	<u>133</u>	2%
Coal royalties revenues by region				
Central Appalachia	\$ 26,194	\$ 21,192	\$ 5,002	24%
Northern Appalachia	2,010	1,949	61	3%
Illinois Basin	2,987	2,862	125	4%
San Juan Basin	3,688	3,994	(306)	(8%)
	<u>\$ 34,879</u>	<u>\$ 29,997</u>	<u>\$ 4,882</u>	16%
Coal royalties per ton by region (\$/ton)				
Central Appalachia	\$ 5.23	\$ 4.56	\$ 0.67	15%
Northern Appalachia	1.88	1.84	0.04	2%
Illinois Basin	2.70	2.50	0.20	8%
San Juan Basin	2.19	2.12	0.07	3%
	<u>\$ 3.93</u>	<u>\$ 3.43</u>	<u>\$ 0.50</u>	15%

Revenues

Coal royalties revenues increased due to higher realized coal royalties per ton. Metallurgical coal is in high demand, driving up the price realized for metallurgical coal sales by our lessees in Central Appalachia.

Coal production increased slightly in the current period. The increase in the Central Appalachia was driven by the metallurgical coal market and lessees trying to meet the demand. Offsetting this increase was decrease in San Juan Basin production. This decrease was attributable to equipment and developmental delays.

Expenses

General and administrative expense increased due to the accelerated vesting of equity compensation. Penn Virginia divested its interest in PVG over the past nine months and no longer owns any limited or general partner interests in PVR. Because the divestiture was considered a change of control under the LTIP, all unvested restricted and phantom units granted to employees performing services for the benefit of PVR were considered vested on the date the last PVG units were sold, June 7, 2010.

DD&A expenses decreased for the comparative periods due to lower levels of timber harvesting.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

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

	<u>Six Months Ended June 30,</u>		<u>Favorable</u>	<u>% Change</u>
	<u>2010</u>	<u>2009</u>	<u>(Unfavorable)</u>	
Financial Highlights				
Revenues				
Coal royalties	\$ 63,105	\$ 60,627	\$ 2,478	4%
Coal services	4,001	3,633	368	10%
Timber	3,051	2,773	278	10%
Oil and gas royalty	1,369	1,248	121	10%
Other	2,616	5,115	(2,499)	(49%)
Total revenues	<u>74,142</u>	<u>73,396</u>	<u>746</u>	1%
Expenses				
Coal royalties	3,086	2,793	(293)	(10%)
Other operating	1,676	1,983	307	15%
General and administrative	9,533	7,755	(1,778)	(23%)
Depreciation, depletion and amortization	14,705	15,558	853	5%
Total expenses	<u>29,000</u>	<u>28,089</u>	<u>(911)</u>	(3%)
Operating income	<u>\$ 45,142</u>	<u>\$ 45,307</u>	<u>\$ (165)</u>	(0%)
Other data				
Coal royalty tons by region				
Central Appalachia	8,941	9,308	(367)	(4%)
Northern Appalachia	2,107	2,117	(10)	(0%)
Illinois Basin	2,189	2,406	(217)	(9%)
San Juan Basin	3,878	3,656	222	6%
Total	<u>17,115</u>	<u>17,487</u>	<u>(372)</u>	(2%)
Coal royalties revenues by region				
Central Appalachia	\$ 44,724	\$ 42,875	\$ 1,849	4%
Northern Appalachia	3,960	3,900	60	2%
Illinois Basin	5,929	6,103	(174)	(3%)
San Juan Basin	8,492	7,749	743	10%
	<u>\$ 63,105</u>	<u>\$ 60,627</u>	<u>\$ 2,478</u>	4%
Coal royalties per ton by region (\$/ton)				
Central Appalachia	\$ 5.00	\$ 4.61	\$ 0.39	8%
Northern Appalachia	1.88	1.84	0.04	2%
Illinois Basin	2.71	2.54	0.17	7%
San Juan Basin	2.19	2.12	0.07	3%
	<u>\$ 3.69</u>	<u>\$ 3.47</u>	<u>\$ 0.22</u>	6%

Revenues

Coal royalties revenues increased due to higher realized coal royalties per ton. Metallurgical coal is in high demand, driving up the price realized for metallurgical coal sales by our lessees in Central Appalachia.

Coal production slightly decreased due to lower longwall mining operations in the Central Appalachian region as operations moved onto adjacent reserves and the closure of a mine in the Illinois Basin due to adverse geological

conditions. These production decreases were partially offset by production increases in the San Juan Basin resulting from the start up of a mine during 2009 and improved mining and market conditions.

Other revenues decreased due to forfeited minimum rentals recognized in the first quarter of 2009 for a property that was not mined in the statutory time period.

Expenses

Coal royalties expenses increased due to an increase in mining activity by our lessees from subleased properties in the Central Appalachian region where our coal royalties expense is primarily incurred. Mining activity on our subleased property fluctuates between periods due to the proximity of our property boundaries and those of other mineral owners.

Operating expenses decreased due to the timing of core hole drilling and other geological studies of coal seams and reserves.

General and administrative expense increased due to the accelerated vesting of equity compensation, noted earlier.

DD&A expenses decreased for the comparative periods due to lower levels of timber harvesting.

Natural Gas Midstream Segment

Three Months Ended June 30, 2010 Compared with Three Months Ended June 30, 2009

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

	<u>Three Months Ended June 30,</u>		<u>Favorable</u>	<u>% Change</u>
	<u>2010</u>	<u>2009</u>	<u>(Unfavorable)</u>	
Financial Highlights				
Revenues				
Residue gas	\$ 77,333	\$ 67,170	\$ 10,163	15%
Natural gas liquids	59,177	38,917	20,260	52%
Condensate	6,313	3,945	2,368	60%
Gathering, processing and transportation fees	3,723	3,028	695	23%
Total natural gas midstream revenues (1)	146,546	113,060	33,486	30%
Equity earnings in equity investment	1,597	629	968	154%
Producer services	707	586	121	21%
Total revenues	<u>148,850</u>	<u>114,275</u>	<u>34,575</u>	30%
Expenses				
Cost of gas purchased (1)	121,659	92,154	(29,505)	(32%)
Operating	7,680	7,227	(453)	(6%)
General and administrative	8,532	4,381	(4,151)	(95%)
Depreciation and amortization	10,884	9,453	(1,431)	(15%)
Total operating expenses	<u>148,755</u>	<u>113,215</u>	<u>(35,540)</u>	(31%)
Operating income	<u>\$ 95</u>	<u>\$ 1,060</u>	<u>\$ (965)</u>	(91%)
Operating Statistics				
System throughput volumes (MMcf)	29,162	31,342	(2,180)	(7%)
Daily throughput volumes (MMcfd)	320	344	(24)	(7%)
Gross margin	\$ 24,887	\$ 20,906	\$ 3,981	19%
Cash impact of derivatives	(421)	3,377	(3,798)	(112%)
Gross margin, adjusted for impact of derivatives	<u>\$ 24,466</u>	<u>\$ 24,283</u>	<u>\$ 183</u>	1%
Gross margin (\$/Mcf)	\$ 0.85	\$ 0.67	\$ 0.18	27%
Cash impact of derivatives (\$/Mcf)	(0.01)	0.10	(0.11)	(110%)
Gross margin, adjusted for impact of derivatives (\$/Mcf)	<u>\$ 0.84</u>	<u>\$ 0.77</u>	<u>\$ 0.07</u>	9%

- (1) For the period of April 1 through June 7, 2010 and for the three months ended June 30, 2009, we recorded \$9.6 million and \$20.1 million of natural gas midstream revenues and \$9.6 million and \$20.1 million for the cost of gas purchased related to the purchase of natural gas from Penn Virginia Oil & Gas, L.P (a subsidiary of Penn Virginia and considered a related party up to June 7, 2010) and the subsequent sale of that gas to third parties. We take title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin.

Gross Margin

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

The gross margin increase was a result of higher commodity pricing and higher fractionation, or frac, spreads offset by decreased system throughput volumes. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMBtu basis. Not all of our system throughput volumes are processed through gas processing plants as some of our systems are only gathering facilities. Processed volumes at our Panhandle facilities increased due to the June 2009 acquisition of the Sweetwater facilities in western Oklahoma, which allows us to process gas that went unprocessed or was processed by third-parties in the past. Processed volumes at our Crossroads facility increased due to the addition of new producer gas.

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. On a per Mcf basis, adjusted for the impact of our commodity derivative instruments, our gross margin increased by \$0.07, or nine percent as compared to the three months ended June 30, 2009. This favorable increase was moderately impacted by commodity derivatives as a result of higher commodity prices during the second quarter of 2010.

Revenues Other Than Gross Margin

Equity earnings in equity investment have grown due to mainline volume increases in the Powder River Basin. Producer services revenues increased due to the relative increase in commodity prices.

Expenses

Operating expenses increased due to prior and current years' expansion projects and acquisitions. The related costs of these facilities include increased costs for compressor rentals and utilities.

General and administrative expense increased due to the accelerated vesting of equity compensation, noted earlier.

Depreciation and amortization expenses increased primarily due to acquisitions and capital expansions on the Panhandle System, including the Sweetwater plant acquisition and Spearman plant construction.

Six Months Ended June 30, 2010 Compared with Six Months Ended June 30, 2009

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

	<u>Six Months Ended June 30,</u>		Favorable	
	<u>2010</u>	<u>2009</u>	(Unfavorable)	% Change
Financial Highlights				
Revenues				
Residue gas	\$ 172,229	\$ 148,364	\$ 23,865	16%
Natural gas liquids	125,820	69,523	56,297	81%
Condensate	13,049	6,848	6,201	91%
Gathering, processing and transportation fees	6,057	5,704	353	6%
Total natural gas midstream revenues (1)	<u>317,155</u>	<u>230,439</u>	<u>86,716</u>	<u>38%</u>
Equity earnings in equity investment	3,280	1,748	1,532	88%
Producer services	1,333	595	738	124%
Total revenues	<u>321,768</u>	<u>232,782</u>	<u>88,986</u>	<u>38%</u>
Expenses				
Cost of gas purchased (1)	263,454	192,774	(70,680)	(37%)
Operating	15,807	14,684	(1,123)	(8%)
General and administrative	13,651	8,749	(4,902)	(56%)
Depreciation and amortization	21,376	18,562	(2,814)	(15%)
Total operating expenses	<u>314,288</u>	<u>234,769</u>	<u>(79,519)</u>	<u>(34%)</u>
Operating income	<u>\$ 7,480</u>	<u>\$ (1,987)</u>	<u>\$ 9,467</u>	<u>476%</u>
Operating Statistics				
System throughput volumes (MMcf)	56,887	63,622	(6,735)	(11%)
Daily throughput volumes (MMcfd)	314	352	(38)	(11%)
Gross margin	\$ 53,701	\$ 37,665	\$ 16,036	43%
Cash impact of derivatives	359	7,169	(6,810)	(95%)
Gross margin, adjusted for impact of derivatives	<u>\$ 54,060</u>	<u>\$ 44,834</u>	<u>\$ 9,226</u>	<u>21%</u>
Gross margin (\$/Mcf)	\$ 0.94	\$ 0.59	\$ 0.35	59%
Cash impact of derivatives (\$/Mcf)	0.01	0.11	(0.10)	(91%)
Gross margin, adjusted for impact of derivatives (\$/Mcf)	<u>\$ 0.95</u>	<u>\$ 0.70</u>	<u>\$ 0.25</u>	<u>36%</u>

- (1) For the period of January 1 through June 7, 2010 and for the six months ended June 30, 2009, we recorded \$27.8 million and \$41.2 million of natural gas midstream revenues and \$27.8 million and \$41.2 million for the cost of gas purchased related to the purchase of natural gas from Penn Virginia Oil & Gas, L.P (a subsidiary of Penn Virginia and considered a related party up to June 7, 2010) and the subsequent sale of that gas to third parties. We take title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin.

Gross Margin

The gross margin increase was a result of higher commodity pricing and higher frac spreads offset by decreased system throughput volumes. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMBtu basis. Not all of our system throughput volumes are processed through gas processing plants as some of our systems are only gathering facilities. Processed volumes at our Panhandle facilities increased due to the June 2009 acquisition of the Sweetwater facilities in western Oklahoma, which allows us to process gas that went unprocessed or was processed by third-parties in the past. Processed volumes at our Crossroads facility increased due to the addition of new producer gas.

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. On a per Mcf basis, adjusted for the impact of our commodity derivative instruments, our gross margin increased by \$0.25, or 36% as compared to the three months ended June 30, 2009. This favorable increase was moderately impacted by commodity derivatives as a result of higher commodity prices during the second quarter of 2010.

Revenues Other Than Gross Margin

Equity earnings in equity investment have grown due to mainline volume increases in the Powder River Basin. Producer services revenues increased due to the relative increase in commodity prices.

Expenses

Operating expenses increased due to prior and current years' expansion projects and acquisitions. The related costs of these facilities include increased costs for compressor rentals and utilities.

General and administrative expense increased due to the accelerated vesting of equity compensation, noted earlier. In addition, general and administrative expenses increased due to increased staffing and related benefit costs.

Depreciation and amortization expenses increased primarily due to acquisitions and capital expansions on the Panhandle System, including the Sweetwater plant acquisition and Spearman plant construction.

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 periods presented:

	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Operating income	\$ 24,876	\$ 21,393	\$ 52,622	\$ 43,320
Other income (expense)				
Interest expense	(8,894)	(6,365)	(14,729)	(11,981)
Other	204	328	512	646
Derivatives	7,074	(2,034)	(494)	(9,195)
Net income	<u>\$ 23,260</u>	<u>\$ 13,322</u>	<u>\$ 37,911</u>	<u>\$ 22,790</u>

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

Source	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Interest on Revolver	\$ 2,376	\$ 4,227	\$ 6,245	\$ 8,504
Interest on Senior Notes	4,400	—	4,400	—
Debt issuance costs and other	1,610	1,369	2,994	1,960
Interest rate swaps	508	918	1,090	1,743
Capitalized interest	—	(149)	—	(226)
Total interest expense	<u>\$ 8,894</u>	<u>\$ 6,365</u>	<u>\$ 14,729</u>	<u>\$ 11,981</u>

Interest expense for the three and six months ended June 30, 2010 has increased compared to the same periods in 2009. These increases are due to the issuance of the Senior Notes bearing an interest rate of 8.25% offset by lower levels of Revolver debt bearing interest at levels of 2.0% to 3.0% over the comparable period. Debt issuance costs have also increase related to Revolver changes in March 2009 and the issuance of the Senior Notes in April 2010.

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, as well as the Interest Rate Swaps.

Commodity markets are volatile, and as a result, our hedging activity results can vary significantly. Our results of operations are affected by the volatility of changes in fair value, which fluctuate with changes in NGL, crude oil and natural gas prices. We determine the fair values of our commodity derivative agreements based on discounted cash flows based on quoted forward prices for the respective commodities. The discounted cash flows utilize 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.

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 caption on our Consolidated Statements of Income.

Our derivative activity for the periods presented is summarized below:

	<u>Three Months Ended June 30,</u>		<u>Six Months Ended June 30,</u>	
	<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
Interest Rate Swap unrealized derivative loss	\$ (50)	\$ 3,574	\$ (754)	\$ 3,416
Interest Rate Swap realized derivative loss	(1,991)	(1,764)	(4,417)	(2,720)
Natural gas midstream commodity unrealized derivative loss	9,536	(7,221)	4,318	(17,060)
Natural gas midstream commodity realized derivative gain	(421)	3,377	359	7,169
Total derivative loss	<u>\$ 7,074</u>	<u>\$ (2,034)</u>	<u>\$ (494)</u>	<u>\$ (9,195)</u>

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 June 30, 2010 and December 31, 2009, our environmental liabilities were \$0.9 million and \$1.0 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.

Critical Accounting 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 estimates which involve the judgment of our management were fully disclosed in our Annual Report on Form 10-K for the year ended December 31, 2009 and remained unchanged as of June 30, 2010.

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.

We have completed a number of acquisitions in recent years. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Changes in operations, further decreases in commodity prices, changes in the business environment or further deteriorations of market conditions could substantially alter management's assumptions and could result in lower estimates of values of acquired assets or of future cash flows. If these events occur, it is reasonably possible that we could record a significant impairment loss on our Consolidated Statements of Income.

Price Risk

Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to seek to mitigate the price risks associated with fluctuations in natural gas, NGL and crude oil prices as they relate to our natural gas midstream 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 June 30, 2010, we reported a net commodity derivative asset related to our natural gas midstream segment of \$1.1 million that is with six counterparties and is substantially concentrated with four 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. No significant uncertainties related to the collectability of amounts owed to us exist with regard to these counterparties.

For the three and six months ended June 30, 2010, we reported a net derivative gain of \$7.1 million and a net derivative loss of \$0.5 million. Because we no longer use hedge accounting for our commodity derivatives, we recognize changes in fair value in earnings currently in the derivatives caption on our 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 to the Consolidated Financial Statements for a further description of our derivatives program.

The following table lists our commodity derivative agreements and their fair values as of June 30, 2010:

	Average Volume Per Day	Swap Price	Weighted Average Price		Fair Value at June 30, 2010 (in thousands)
			Put	Call	
Crude oil collar	(barrels)		(per barrel)		
Third quarter 2010 through fourth quarter 2010	750		\$ 70.00	\$ 81.25	\$ (89)
Crude oil collar	(barrels)		(per barrel)		
Third quarter 2010 through fourth quarter 2010	1,000		\$ 68.00	\$ 80.00	\$ (289)
Natural gas purchase swap	(MMBtu)	(MMBtu)			
Third quarter 2010 through fourth quarter 2010	7,100	\$ 5.885			\$ (1,378)
NGL - natural gasoline collar	(gallons)		(per gallon)		
Third quarter 2010 through fourth quarter 2010	42,000		\$ 1.55	\$ 2.03	\$ 435
NGL - natural gasoline collar	(gallons)		(per gallon)		
First quarter 2011 through fourth quarter 2011	95,000		\$ 1.57	\$ 1.94	\$ 2,374
Crude oil collar	(barrels)		(per barrel)		
First quarter 2011 through fourth quarter 2011	400		\$ 75.00	\$ 98.50	\$ 629
Natural gas purchase swap	(MMBtu)	(MMBtu)			
First quarter 2011 through fourth quarter 2011	6,500	\$ 5.796			\$ (1,053)
Settlements to be received in subsequent period					<u>\$ 453</u>
					<u>\$ 1,082</u>

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 \$1.5 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 \$1.3 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 swaps by \$3.4 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 swaps by \$3.4 million. We estimate that a \$0.10 per gallon increase in the natural gasoline (an NGL) price would decrease the fair value of our natural gasoline collar by \$2.7 million. We estimate that a \$0.10 per gallon decrease in the natural gasoline price would increase the fair value of our natural gasoline collar by \$2.6 million.

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 2010 would increase or decrease by \$0.9 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 2010 would increase or decrease by \$3.1 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 June 30, 2010, we had \$346.5 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. From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total \$250.0 million, or 72% of our outstanding indebtedness under the Revolver as of June 30, 2010, 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 29% of our outstanding indebtedness under the Revolver as of June 30, 2010, 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 June 30, 2010 would cost us approximately \$1.0 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 to the Consolidated 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 six months ended June 30, 2010, two of our natural gas midstream segment customers accounted for \$55.1 million and \$41.0 million, or 14% and 10%, of our total consolidated revenues. At June 30, 2010, 21% 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 June 30, 2010, no receivables were collateralized, and we had a \$0.2 million allowance for doubtful accounts, of which the majority 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 June 30, 2010. 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 June 30, 2010, 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

The following risk factors should be read in conjunction with the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2009. Risk factors listed below are updates or additional risk factors to consider.

Concerns about the environmental impacts of fossil-fuel emissions, including perceived impacts on global climate change, are resulting in increased regulation of emissions of greenhouse gases in many jurisdictions and increased interest in and the likelihood of further regulation, which could significantly affect our coal royalties revenues.

Global climate change continues to attract considerable public and scientific attention. Several widely publicized scientific reports have engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. Legislative attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. Such legislation was introduced in Congress in the last several years to reduce greenhouse gas emissions in the United States and further proposals or amendments are likely to be offered in the future. In anticipation of the endangerment finding of the Environmental Protection Agency, or the EPA, regarding greenhouse gas emissions (which was finalized in December 2009), the agency proposed two sets of rules regarding possible future regulation of greenhouse gas emissions under the Clean Air Act. Enactment of laws, passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions could result in electric generators switching from coal to other fuel sources.

On June 21, 2010, EPA released a proposed rule that would classify byproducts of coal combustion (“CCB”) either as hazardous wastes under subtitle C of RCRA, or as solid wastes under Subtitle D. If CCB were classified as a hazardous waste, regulations may, among other requirements, restrict ash disposal, regulate coal ash storage facilities more stringently, require groundwater monitoring and mandate financial assurance.

More recently, on June 3, 2010, EPA issued a final rule setting forth a more stringent primary National Ambient Air Quality Standard (NAAQS) applicable to air emissions of sulfur dioxide. Coal-fired power plants, which are the largest end users of coal mined from our reserves, may be required to install additional emissions control equipment or take other steps to lower sulfur emissions as a result. Individually and collectively, these developments could add additional costs of the use of coals as a fuel, adversely affect the use of and demand for fossil fuels, particularly coal, and may encourage power plant operators to switch to a different fuel.

Delays in our lessees obtaining mining permits and approvals, or the inability to obtain required permits and approvals, could have an adverse effect on our coal royalties revenues.

Mine operators, including our lessees, must obtain numerous permits and approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. For example, on March 26, 2010, the EPA announced a proposal to exercise its Section 404(c) “veto” power with regard to the Spruce No. 1 Surface Mine in West Virginia, which was previously permitted in 2007. This would be the first time the EPA’s Section 404(c) “veto” power would be applied to a previously permitted project. Moreover, on April 1, 2010, the EPA issued interim final guidance substantially revising the environmental review of Section 402 and Section 404 permits by state and federal agencies. As an example of the significance of this guidance, the EPA also published on April 1, 2010 a proposed determination to prohibit, restrict or deny a permit issued under Section 404 to Mingo Logan Coal Company for the discharge of dredged fill in connection with the construction of various fills and sedimentation ponds. Of course, this guidance has just been issued and it remains to be seen how it will be applied by the EPA and whether it will be subject to judicial challenge by affected states or private parties. These initiatives have extended the time required to obtain permits for coal mining and we anticipate further delays in obtaining permits and that the costs associated with obtaining and complying with those permits will increase substantially. It is possible that some projects may not be able to obtain these permits because of the manner in which these rules are being interpreted and applied. Limitations on our lessees’ ability to conduct their mining operations due to the inability to obtain or renew necessary permits, or due to uncertainty, litigation or delays associated with the eventual issuance of these permits, could have an adverse effect on our coal royalties revenues.

Recently, on June 17, 2010, the U.S. Army Corps announced the suspension of all NWP 21 permits in six Appalachian region states until the Corps takes further action on NWP 21, or until NWP 21 expires on March 18, 2012. All proposed surface coal mining projects in these states that involve discharges of dredged or fill material into waters of the United States will have to obtain individual permits from the Corps. The elimination of this method for obtaining permits may add to the costs and delays in obtaining individual permits for coal mining operations.

Our lessees' mining operations are subject to extensive and costly laws and regulations, which could increase operating costs and limit our lessees' ability to produce coal, which could have an adverse effect on our coal royalties revenues.

Our lessees are subject to numerous and detailed federal, state and local laws and regulations affecting coal mining operations, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. Our lessees are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be significant and time-consuming and may delay commencement or continuation of exploration or production operations. Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that are likely to result in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. Moreover, workplace accidents, such as the April 5, 2010, Upper Big Branch Mine, West Virginia incident, may result in more stringent enforcement as well as the development of new laws and regulations. The possibility exists that new laws or regulations (or judicial interpretations of existing laws and regulations) may be adopted in the future that could materially affect our lessees' mining operations, either through direct impacts such as new requirements impacting our lessees' existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit coal consumers' use of coal. Any of these direct or indirect impacts could have an adverse effect on our coal royalties revenues.

Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by our lessees can be eliminated completely. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens and, to a lesser extent, the issuance of injunctions to limit or cease operations. Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our lessees are required to pay these costs and liabilities and if their financial viability is affected by doing so, then their mining operations and, as a result, our coal royalties revenues, could be adversely affected.

On June 28, 2010, the EPA issued final regulations to require owners and operators of certain underground coal mines with annual greenhouse gas emissions in excess of 25,000 tons of carbon dioxide per year to monitor and report greenhouse gas emissions. Subject coal mines will be required to begin monitoring as of January 1, 2011, and report emissions of greenhouse gases by March of the following year. The regulations do not require that underground coal mines install and implement controls to restrict greenhouse gas emissions, however, the costs of complying with these regulations may be material and could reduce royalties from our lessees.

Expanding our natural gas midstream business by constructing new gathering systems, pipelines and processing facilities subjects us to construction risks.

One of the ways we may grow our natural gas midstream business is through the construction of additions to existing gathering, compression and processing systems. The construction of a new gathering system or pipeline, the expansion of an existing pipeline through the addition of new pipe or compression and the construction of new processing facilities involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. Our access to such capital is currently adversely impacted by the state of the global economy, including financial and credit markets. If we do undertake these projects, they may not be completed on schedule, or at all, or at the anticipated cost. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For example, the construction of gathering facilities requires the expenditure of significant amounts of capital, which may exceed our estimates. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. As a result, there is the risk that new facilities, including the facilities we are constructing in the Marcellus Shale formation in north central Pennsylvania under our contract with Range Resources Corporation, or Range, may not be able to attract enough natural gas to achieve our expected investment return, which could have a material adverse effect on our business, results of operations or financial condition.

Federal and/or state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the exploitation of the Marcellus Shale formation, which may adversely affect the supply of natural gas to our planned Marcellus Shale system.

The United States Congress is currently considering legislation to amend the Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities. Similar legislation is under consideration in various states, including New York, and state environmental agencies may impose new requirements on these practices under existing laws. Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formation to stimulate natural gas production. Range and other producers who are active in the Marcellus Shale formation use hydraulic fracturing to produce commercial quantities of natural gas and oil from shale formations such as the Marcellus Shale. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal and/or state levels, exploration and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements, which could include public review and possibly even rights to challenge permitting. Individually or collectively, such new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. In this case, the ability of such producers to supply our planned Marcellus Shale system with natural gas may be diminished, which could, in turn, adversely affect our revenues.

Beginning in 2013, recently enacted legislation will result in an additional 3.8% tax on income earned by common unitholders with respect to their investments in us.

The recently enacted Patient Protection and Affordable Care Act of 2010, as amended by the Health Care and Education Affordability Reconciliation Act of 2010, is scheduled to impose a 3.8% Medicare tax on net investment income earned by certain individuals, estates and trusts for taxable years beginning after December 31, 2012. For these purposes, net investment income generally includes a unitholder's allocable share of our income and gain realized by a unitholder from a sale of units. In the case of an individual, the tax will be imposed on the lesser of (1) the unitholder's net investment income or (2) the amount by which the unitholder's modified adjusted gross income exceeds \$250,000 (if the unitholder is married and filing jointly or a surviving spouse), \$125,000 (if the unitholder is married and filing separately) or \$200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (1) undistributed net investment income, or (2) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Certain federal income tax preferences currently available with respect to coal exploration and development may be eliminated as a result of future legislation.

Among the proposed legislative changes contained in the President's Budget Proposal for Fiscal Year 2011 is the elimination of certain key U.S. federal income tax preferences relating to coal exploration and development. The Budget Proposal would (i) require capitalization of exploration and development costs relating to coal and other hard mineral fossil fuels, (ii) repeal the percentage depletion allowance with respect to coal properties, (iii) repeal capital gains treatment of coal and lignite royalties and (iv) exclude from the definition of domestic production gross receipts all gross receipts derived from the sale, exchange, or other disposition of coal, other hard mineral fossil fuels, or primary products thereof. These proposed legislative changes could adversely affect our lessees and our unitholders. Passage of such proposed legislative changes or similar changes in U.S. federal income tax laws could increase the amount of taxable income allocable to our unitholders, increase the tax liability of unitholders with respect to an investment in us and negatively impact the value of an investment in our units.

Item 6 *Exhibits*

- 10.1 Underwriting Agreement, dated April 22, 2010, among Penn Virginia Resource Partners, L.P., Penn Virginia Resource Finance Corporation, the subsidiary guarantors named therein and the representatives of the several underwriters named therein relating to the 8 1/4% Senior Notes due 2018 (incorporated by reference to Exhibit 1.1 to Registrant's Current Report on Form 8-K filed on April 27, 2010).
- 10.2 Second Amendment to Amended and Restated Credit Agreement, dated as of June 7, 2010, by and among PVR Finco LLC, the guarantors party thereto, PNC Bank, National Association, as Administrative Agent, and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 7, 2010).
- 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: July 30, 2010

By: /s/ Robert B. Wallace
Robert B. Wallace
Executive Vice President and Chief Financial Officer

Date: July 30, 2010

By: /s/ Forrest W. McNair
Forrest W. McNair
Vice President and Controller

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

	Year Ended December 31,					Six Months Ended
	2005	2006	2007	2008	2009	June 30, 2010
Earnings						
Pre-tax income *	\$52,430	\$74,910	\$55,552	\$103,603	\$62,452	\$ 40,302
Fixed charges	14,351	19,783	19,766	26,850	27,368	16,158
Total earnings	<u>\$66,781</u>	<u>\$94,693</u>	<u>\$75,318</u>	<u>\$130,453</u>	<u>\$89,820</u>	<u>\$ 56,460</u>
Fixed Charges						
Interest expense	\$14,053	\$19,151	\$18,896	\$ 25,346	\$24,878	\$ 14,730
Rental interest factor	298	632	870	1,504	2,490	1,428
Total fixed charges	<u>\$14,351</u>	<u>\$19,783</u>	<u>\$19,766</u>	<u>\$ 26,850</u>	<u>\$27,368</u>	<u>\$ 16,158</u>
Ratio of earnings to fixed charges	4.7x	4.8x	3.8x	4.9x	3.3x	3.5x

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

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

I, William H. Shea, Jr., 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: July 30, 2010

/s/ William H. Shea, Jr.

William H. Shea, Jr.
Chief Executive Officer

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

I, Robert B. Wallace, Executive 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: July 30, 2010

/s/ Robert B. Wallace

Robert B. Wallace

Executive Vice President and Chief Financial Officer

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended June 30, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William H. Shea, Jr., 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: July 30, 2010

/s/ William H. Shea, Jr.

William H. Shea, Jr.

Chief Executive Officer

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

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Penn Virginia Resource Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended June 30, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert B. Wallace, Executive 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: July 30, 2010

/s/ Robert B. Wallace

Robert B. Wallace

Executive 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.