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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2005

Or

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

For the transition period from ____________ To ____________

Commission File Number 1-13283

PENN VIRGINIA CORPORATION
(Exact Name of Registrant as Specified in Its Charter)

Virginia	23-1184320
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

THREE RADNOR CORPORATE CENTER, SUITE 230
100 MATSONFORD ROAD
RADNOR, PA 19087

(Address of Principal Executive Office) (Zip Code)

(610) 687-8900
(Registrant's Telephone Number, Including Area Code)

(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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

Yes X No ____

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes X No ____

As of August 1, 2005, 18,513,586 shares of common stock of the Registrant were issued and outstanding.

PENN VIRGINIA CORPORATION
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PART I. Financial Information
Item 1. Financial Statements

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME – Unaudited
(in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Revenues				
Natural gas	$ 44,680	$ 32,444	$ 82,940	$ 66,408
Oil and condensate	3,346	3,030	6,759	6,518
Natural gas midstream	86,995	-	113,273	-
Coal royalties	20,129	17,517	38,182	34,377
Other	4,594	1,578	6,800	2,892
Total revenues	159,744	54,569	247,954	110,195
Expenses				
Cost of gas purchased	74,374	-	96,211	-
Operating	8,402	5,469	13,501	10,313
Exploration	17,931	1,835	25,590	7,395
Taxes other than income	4,054	2,464	7,401	5,494
General and administrative	8,787	5,749	15,507	11,431
Depreciation, depletion and amortization	19,779	13,387	35,623	27,543
Total expenses	133,327	28,904	193,833	62,176
Operating income	26,417	25,665	54,121	48,019
Other income (expense)				
Interest expense	(3,497)	(1,464)	(6,875)	(2,854)
Interest and other income	376	258	695	532
Unrealized loss on derivatives	(447)	-	(14,764)	-
Income before minority interest and income taxes	22,849	24,459	33,177	45,697
Minority interest	10,246	4,695	8,590	9,198
Income tax expense	4,956	7,684	9,900	14,277
Net income	$ 7,647	$ 12,080	$ 14,687	$ 22,222
Net income per share, basic	$ 0.41	$ 0.66	$ 0.79	$ 1.22
Net income per share, diluted	$ 0.41	$ 0.65	$ 0.79	$ 1.21
Weighted average shares outstanding, basic	18,517	18,293	18,503	18,230
Weighted average shares outstanding, diluted	18,719	18,479	18,706	18,396

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

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	June 30, 2005 (Unaudited)	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 26,286	$ 25,471
Accounts receivable	81,211	40,003
Income taxes receivable	6,412	4,389
Assets held for sale	-	9,694
Inventory	3,448	853
Derivative assets	1,822	1,133
Prepaid expenses and other	2,512	2,696
Total current assets	121,691	84,239
Property and equipment		
Oil and gas properties (successful efforts method)	656,002	591,100
Other property and equipment	449,872	274,191
Less: Accumulated depreciation, depletion and amortization	(233,332)	(199,803)
Net property and equipment	872,542	665,488
Equity investments	28,485	27,881
Goodwill	6,931	-
Intangibles, net	38,413	-
Other assets	8,928	5,727
Total assets	$ 1,076,990	$ 783,335
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 6,402	$ 4,800
Accounts payable and accrued liabilities	74,874	35,252
Derivative liabilities	15,049	1,723
Total current liabilities	96,325	41,775
Other liabilities	19,735	18,095
Derivative liabilities	9,088	876
Deferred income taxes	100,055	97,912
Long-term debt of the Company	89,000	76,000
Long-term debt of PVR	197,250	112,926
Minority interest in PVR	305,515	182,891
Shareholders' equity		
Preferred stock of $100 par value – 100,000 shares authorized; none issued	-	-
Common stock of $0.01 par value – 32,000,000 shares authorized; 18,511,859 and 18,476,331 shares issued and outstanding at June 30, 2005, and December 31, 2004, respectively	185	185
Paid-in capital	86,945	85,543
Retained earnings	179,247	168,726
Accumulated other comprehensive income	(4,248)	(720)
Treasury stock and other	(2,107)	(874)
Total shareholders' equity	260,022	252,860
Total liabilities and shareholders' equity	$ 1,076,990	$ 783,335

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

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS - Unaudited
(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Cash flows from operating activities				
Net income	$ 7,647	$ 12,080	$ 14,687	$ 22,222
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	19,779	13,387	35,623	27,543
Unrealized loss (gain) on derivatives, net of settlements	(1,394)	-	12,923	-
Minority interest	10,246	4,695	8,590	9,198
Deferred income taxes	500	4,423	4,043	6,964
Dry hole and unproved leasehold expense	16,477	964	18,916	2,646
Other	289	1,086	1,889	2,136
Changes in operating assets and liabilities:				
Accounts receivable	31	(4,863)	(5,347)	(890)
Other current assets	(2,503)	(2,046)	(1,652)	(6,401)
Accounts payable and accrued expenses	4,126	3,557	(4,970)	(6,720)
Other assets and liabilities	(1,383)	772	(36)	1,901
Net cash provided by operating activities	53,815	34,055	84,666	58,599
Cash flows from investing activities				
Acquisitions, net of cash acquired	(17,693)	-	(222,677)	415
Additions to property and equipment	(40,374)	(34,114)	(77,960)	(49,629)
Proceeds from sale of properties	985	37	10,751	-
Other	-	58	-	208
Net cash used in investing activities	(57,082)	(34,019)	(289,886)	(49,006)
Cash flows from financing activities				
Dividends paid	(2,082)	(2,060)	(4,163)	(4,111)
Distributions paid to minority interest holders of PVR	(7,968)	(5,351)	(13,756)	(10,779)
Proceeds from PVR's common unit offering	1,251	-	126,436	-
Proceeds from borrowings of the Company	24,000	10,000	41,000	10,000
Repayments of borrowings of the Company	(13,000)	(2,000)	(28,000)	(11,000)
Proceeds from borrowings of PVR	15,000	-	226,800	-
Repayments of borrowings of PVR	(9,300)	(1,000)	(140,800)	(1,000)
Payments for debt issuance costs	-	-	(2,039)	-
Issuance of stock and other	60	1,863	557	3,803
Net cash provided by (used in) financing activities	7,961	1,452	206,035	(13,087)
Net increase (decrease) in cash and cash equivalents	4,694	1,488	815	(3,494)
Cash and cash equivalents – beginning of period	21,592	13,026	25,471	18,008
Cash and cash equivalents – end of period	$ 26,286	$ 14,514	$ 26,286	$ 14,514
Supplemental disclosures				
Cash paid during the periods for:				
Interest (net of amounts capitalized)	$ 2,240	$ 157	$ 5,571	$ 3,016
Income taxes	$ 7,660	$ 3,302	$ 7,660	$ 3,609
Noncash investing and financing activities				
Issuance of PVR units for acquisition	$ -	$ -	$ -	$ 1,060

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

PENN VIRGINIA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Unaudited

June 30, 2005

1. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements include the accounts of Penn Virginia Corporation ("Penn Virginia," "PVA," the "Company," "we" or "our"), all wholly-owned subsidiaries of the Company, and Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"), of which we indirectly own the sole two percent general partner interest and an approximately 37 percent limited partner interest. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial reporting and Securities and Exchange Commission ("SEC") regulations. These statements involve the use of estimates and judgments where appropriate. In the opinion of management, all adjustments, consisting of normal recurring accruals, considered necessary for a fair presentation have been included. These financial statements should be read in conjunction with our consolidated financial statements and footnotes included in our Annual Report on Form 10-K for the year ended December 31, 2004. Operating results for the six months ended June 30, 2005, are not necessarily indicative of the results that may be expected for the year ending December 31, 2005. Certain reclassifications have been made to conform to the current period's presentation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Natural Gas Midstream Revenues

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

Goodwill

We had approximately $6.9 million of goodwill at June 30, 2005, based on the preliminary purchase price allocation for the Cantera Acquisition (as defined in Note 3) in March 2005. This amount may change based on the final purchase price allocation. The goodwill has been allocated to the midstream segment. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 142, *Goodwill and Other Intangible Assets,* goodwill will be assessed at least annually for impairment. We intend to test goodwill for impairment during the fourth quarter of each fiscal year.

Intangibles

Intangible assets at June 30, 2005, included $35.5 million for customer contracts and relationships and $4.6 million for rights of way. These amounts may change based on the final purchase price allocation as described in Note 3. Customer contracts and relationships are amortized on a straight-line basis over the expected useful lives of the individual contracts and relationships, which do not exceed 15 years. Rights-of-way are amortized on a straight-line basis over a period of 15 years. Total intangible amortization was approximately $1.2 million and $1.6 million during the three months and six months ended June 30, 2005, respectively. There were no intangible assets or related amortization in 2004. As of June 30, 2005, accumulated amortization of intangible assets was $1.6 million.

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

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

3. ACQUISITION OF NATURAL GAS MIDSTREAM BUSINESS

On March 3, 2005, PVR completed the acquisition (the "Cantera Acquisition") of Cantera Gas Resources, LLC ("Cantera"), a midstream gas gathering and processing company with primary locations in the mid-continent area of Oklahoma and the panhandle of Texas. The midstream business operates as PVR Midstream LLC, a subsidiary of Penn Virginia Operating Co., LLC, which is a wholly owned subsidiary of the Partnership. As a result of the Cantera Acquisition, PVR owns and operates a significant set of midstream assets that includes approximately 3,400 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 million cubic feet per day (MMcfd) of total capacity. The midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. The Partnership believes that the Cantera Acquisition will establish a platform for future growth in the natural gas midstream sector and will diversify its cash flows into another long-lived asset base. The results of operations of PVR Midstream LLC since March 3, 2005, the closing date of the Cantera Acquisition, are included in the accompanying consolidated statements of income.

Total cash paid for the Cantera Acquisition was approximately $198 million, which PVR funded with a $110 million term loan and with borrowings under the Partnership's revolving credit facility. The purchase price allocation for the Cantera Acquisition has not been finalized because PVR is still in the process of settling various post-closing adjustments with the seller and obtaining final appraisals of assets acquired and liabilities assumed. PVR used proceeds of $129 million, including a $2.6 million contribution from the general partner, from PVR's sale of common units in a subsequent public offering in March 2005 to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Cantera Acquisition based upon preliminary fair values on the date of acquisition, as follows (in thousands):

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

The preliminary purchase price allocation includes approximately $6.9 million of goodwill. The significant factors that contributed to the recognition of goodwill include PVR's entry into the natural gas midstream business and PVR's ability to acquire an established business with an assembled workforce. Under SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill recorded in connection with a business combination is not amortized, but rather is tested for impairment at least annually. Accordingly, the unaudited pro forma financial information presented below does not include amortization of the goodwill recorded in the acquisition. The preliminary purchase price allocation includes approximately $40.1 million of intangible assets that are primarily associated with assumed customer contracts, customer relationships and rights of way.

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

The following unaudited pro forma financial information reflects the consolidated results of operations of the Company as if the Cantera Acquisition, the closing of PVR's amended credit facility (see Note 7) and the March 2005 public offering of PVR's common units had occurred on January 1 of the reported period. The pro forma information includes primarily adjustments for depreciation of acquired property and equipment, amortization of intangibles, interest expense for acquisition debt and the change in weighted average common shares resulting from the public offering. The pro forma financial information is not necessarily indicative of the results of operations as it would have been had these transactions been effected on the assumed date.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(in thousands, except share data)			
Revenues	$ 159,744	$ 70,429	$ 266,318	$ 142,408
Net income	$ 7,647	$ 12,417	$ 14,778	$ 22,245
Net income per share, basic	$ 0.41	$ 0.68	$ 0.80	$ 1.22
Net income per share, diluted	$ 0.41	$ 0.67	$ 0.79	$ 1.21

4. SALE OF TEXAS PROPERTIES

On January 24, 2005, we completed the sale of certain oil and gas properties in Texas for cash proceeds of $9.7 million. These properties were classified as assets held for sale on the consolidated balance sheet as of December 31, 2004. As part of the sale agreement, we will receive a 20 percent net profits interest in one of the properties beginning January 1, 2006. In addition, the buyer has agreed to perform a waterflood technique on this property. If the buyer fails to complete the waterflood technique within specified deadlines, then under certain conditions the buyer would be liable to pay us additional proceeds of $0.5 million.

5. STOCK-BASED COMPENSATION

We have stock compensation plans that allow, among other grants, incentive and nonqualified stock options to be granted to key employees and officers and nonqualified stock options to be granted to directors. We account for those plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations. No stock-based employee compensation cost related to stock options is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The table below illustrates the effect on net income and earnings per share as if we had applied the fair value recognition provision of SFAS No. 123, *Accounting for Stock-Based Compensation*, to stock-based employee options (in thousands, except per share data).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Net income, as reported	$ 7,647	$ 12,080	$ 14,687	$ 22,222
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	286	149	484	217
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(482)	(303)	(827)	(540)
Pro forma net income	$ 7,451	$ 11,926	$ 14,344	$ 21,899
Earnings per share				
Basic - as reported	$ 0.41	$ 0.66	$ 0.79	$ 1.22
Basic - pro forma	$ 0.40	$ 0.65	$ 0.78	$ 1.20
Diluted - as reported	$ 0.41	$ 0.65	$ 0.79	$ 1.21
Diluted - pro forma	$ 0.40	$ 0.65	$ 0.77	$ 1.19

6. HEDGING ACTIVITIES

Commodity Cash Flow Hedges

Oil and Gas Segment. The fair values of our oil and gas derivative contracts are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of June 30, 2005. The following table sets forth our positions as of June 30, 2005:

	Average Volume Per Day	Weighted Average Price Collars Floor		Weighted Average Price Collars Ceiling		Estimated Fair Value	
Natural Gas Costless Collars	**(in Mmbtus)**		**(per Mmbtu)**			**(in thousands)**	
Third Quarter 2005	30,000	$	5.60	$	7.59	$	(719)
Fourth Quarter 2005	29,000	$	5.76	$	8.68		(970)
First Quarter 2006	20,689	$	5.73	$	9.41		(1,609)
Second Quarter 2006	11,648	$	5.14	$	10.04		(145)
Third Quarter 2006	4,000	$	6.50	$	9.32		(17)
Fourth Quarter 2006	4,000	$	6.50	$	9.32		(132)
Crude Oil Costless Collars	**(in Bbls)**		**(per Bbl)**				
Third Quarter 2005	200	$	42.00	$	47.75		(241)
Fourth Quarter 2005	200	$	42.00	$	47.75		(220)
First Quarter 2006 (January and February only)	200	$	42.00	$	47.75		(145)
Total						$	(4,198)

Based upon our assessment of our derivative agreements designated as cash flow hedges at June 30, 2005, we reported (i) a net derivative liability of approximately $4.2 million and (ii) a loss in accumulated other comprehensive income of $2.7 million, net of a related income tax benefit of $1.5 million. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $0.7 million and $1.0 million for the three months and six months ended June 30, 2005, respectively. Based upon future oil and natural gas prices as of June 30, 2005, $4.0 million of hedging losses are expected to be realized within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. We recognized net hedging losses of $1.2 million and $2.5 million for the three months and six months ended June 30, 2004, respectively.

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

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

	Average Volume Per Day	Weighted Average Price	Estimated Fair Value (in thousands)
Ethane Swaps	**(in gallons)**	**(per gallon)**	$ (2,910)
Third Quarter 2005 through Fourth Quarter 2006	68,880	$ 0.4770	
First Quarter 2007 through Fourth Quarter 2007	34,440	$ 0.5050	
First Quarter 2008 through Fourth Quarter 2008	34,440	$ 0.4700	
Propane Swaps	**(in gallons)**	**(per gallon)**	(4,725)
Third Quarter 2005 through Fourth Quarter 2006	52,080	$ 0.7060	
First Quarter 2007 through Fourth Quarter 2007	26,040	$ 0.7550	
First Quarter 2008 through Fourth Quarter 2008	26,040	$ 0.7175	
Crude Oil Swaps	**(in Bbls)**	**(per Bbl)**	(11,456)
Third Quarter 2005 through Fourth Quarter 2006	1,100	$ 44.45	
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	
Natural Gas Swaps	**(in MMbtu)**	**(per MMbtu)**	4,472
Third Quarter 2005 through Fourth Quarter 2006	7,500	$ 7.05	
First Quarter 2007 through Fourth Quarter 2008	4,000	$ 6.97	
			$ (14,619)

Based upon the assessment of derivative agreements designated as cash flow hedges at June 30, 2005, PVR reported (i) a net derivative liability related to the natural gas midstream segment of approximately $14.6 million, (ii) a loss in accumulated other comprehensive income of $1.1 million, net of a related income tax benefit of $0.6 million, and (iii) an unrealized loss on derivatives of $0.8 million for hedge ineffectiveness. In connection with monthly settlements, PVR recognized net hedging gains in natural gas midstream revenues of $0.8 million for the three months and six months ended June 30, 2005, and net hedging losses in cost of gas purchased of $0.2 million for the three months and six months ended June 30, 2005. Based upon future commodity prices as of June 30, 2005, $8.3 million of hedging losses are expected to be realized within the next 12 months. The amounts that PVR will ultimately realize will vary due to changes in the fair value of the open derivative agreements prior to settlement. Because all hedged volumes relate to periods beginning after March 31, 2005, PVR had no monthly settlements and recognized no net hedging losses in natural gas midstream revenues in 2004.

Interest Rate Swap

In connection with the issuance of its senior unsecured notes (see Note 7), PVR entered into an interest rate swap agreement with an original notional amount of $30 million to hedge a portion of the fair value of those notes. The notional amount decreased by one-third of each principal payment. Under the terms of the interest rate swap agreement, the counterparty paid a fixed rate of 5.77 percent on the notional amount and received a variable rate equal to the floating interest rate which was determined semi-annually and was based on the six month London Interbank Offering Rate plus 2.36 percent. Settlements on the swap were recorded as interest expense. In conjunction with the closing of the Cantera Acquisition on March 3, 2005, PVR entered into an amendment to the senior unsecured notes in which it agreed to a 0.25 percent increase in the fixed interest rate on the senior unsecured notes, from 5.77 percent to 6.02 percent. This swap was designated as a fair value hedge because it had been determined that it was highly effective in mitigating the change in fair value of the hedged portion of the notes.

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

7. LONG-TERM DEBT

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

	June 30, 2005 (Unaudited)	December 31, 2004
Penn Virginia revolving credit facility	$ 89,000	$ 76,000
PVR revolving credit facility	117,500	30,000
PVR senior unsecured notes*	86,152	87,726
	292,652	193,726
Less: Current maturities	(6,402)	(4,800)
	$ 286,250	$ 188,926

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

Concurrent with the closing of the Cantera Acquisition, Penn Virginia Operating Co., LLC, the parent of PVR Midstream LLC and a subsidiary of the Partnership, entered into a new unsecured $260 million, five-year credit agreement consisting of a $150 million revolving credit facility that matures in March 2010 and a $110 million term loan. As of June 30, 2005, the new credit agreement consisted of a $150 million revolving credit facility. A portion of the revolving credit facility and the term loan were used to fund the Cantera Acquisition and to repay borrowings under PVR's previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million of PVR's common units in March 2005 were used to repay the $110 million term loan and a portion of the amount outstanding under the revolving credit facility. The term loan cannot be re-borrowed. The revolving credit facility is available for general Partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. As of June 30, 2005, PVR had a one-time option under the revolving credit facility to increase the facility by an additional $100 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders.

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

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

Upon settlement of the interest rate swap agreement (see Note 6), the $0.8 million negative fair value adjustment of the carrying amount of long-term debt will be amortized as interest expense over the remaining term of the Notes using the interest rate method.

8. COMMITMENTS AND CONTINGENCIES

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, management believes these claims will not have a material effect on our financial position, liquidity or operations.

In June 2005, we entered into an agreement to purchase oil and gas well drilling services from a third party over the next two years. The agreement includes early termination provisions that would require us to pay a penalty if we terminate the agreement prior to the original two-year term. The amount of the penalty is based on the number of days remaining in the two-year term and declines as time passes. As of June 30, 2005, the penalty amount would have been $5.7 million if we had terminated the agreement on that date. Management intends to utilize drilling services under this agreement for the full two-year term and has no plans to terminate the agreement early.

9. PENSION PLANS AND OTHER POSTRETIREMENT BENEFITS

In accordance with SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits*, the following table provides the components of net periodic benefit costs for the respective plans shown for the three months and six months ended June 30, 2005 and 2004 (in thousands):

	Pension				Post-retirement Healthcare			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004	2005	2004	2005	2004
Service cost	$ -	$ -	$ -	$ -	$ 7	$ 6	$ 14	$ 12
Interest cost	33	37	65	74	66	71	131	142
Amortization of prior service cost	2	1	3	2	22	22	44	44
Amortization of transitional obligation	1	1	2	2	-	-	-	-
Recognized actuarial (gain) loss	7	5	15	10	13	11	26	22
Net periodic benefit cost	$ 43	$ 44	$ 85	$ 88	$ 108	$ 110	$ 215	$ 220

Contributions paid to the pension and post-retirement healthcare plans during the three months and six months ended June 30, 2005, were $0.1 million and $0.3 million, respectively. We expect to contribute a total of approximately $0.7 million to our pension and other postretirement benefit plans during 2005.

10. EARNINGS PER SHARE

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the three months and six months ended June 30, 2005 and 2004 (in thousands, except per share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Net income	$ 7,647	$ 12,080	$ 14,687	$ 22,222
Weighted average shares, basic	18,517	18,293	18,503	18,230
Effect of dilutive securities:				
Stock options	202	186	203	166
Weighted average shares, diluted	18,719	18,479	18,706	18,396
Net income per share, basic	$ 0.41	$ 0.66	$ 0.79	$ 1.22
Net income per share, diluted	$ 0.41	$ 0.65	$ .079	$ 1.21

11. COMPREHENSIVE INCOME

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net income	$ 7,647	$ 12,080	$ 14,687	$ 22,222
Unrealized holding gains (losses) on hedging activities, net of tax	2,592	(976)	(3,778)	(3,049)
Reclassification adjustment for hedging activities, net of tax	54	782	250	1,612
Comprehensive income	$ 10,293	$ 11,886	$ 11,159	$ 20,785

12. SEGMENT INFORMATION

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

Oil and Gas – crude oil and natural gas exploration, development and production.

Coal (the "PVR Coal" segment) – the leasing of mineral interests and subsequent collection of royalties, the providing of fee-based coal handling, transportation and processing infrastructure facilities, and the development and harvesting of timber.

Natural Gas Midstream (the "PVR Midstream" segment) – gas processing, gathering and other related services.

Corporate and Other – primarily represents corporate functions.

In our Annual Report on Form 10-K for the year ended December 31, 2004, we reported three segments – oil and gas, coal, and corporate and other. As a result of the Cantera Acquisition, we added the natural gas midstream segment. The following segment information for the three months and six months ended June 30, 2004, has been restated to conform to the current period's presentation. The following is a summary of certain financial information relating to our segments (in thousands):

	Oil and Gas	PVR Coal	PVR Midstream	Corporate and Other	Consolidated
For the three months ended June 30, 2005:					
Revenues	$ 48,129	$ 23,693	$ 87,661	$ 261	$ 159,744
Cost of gas purchased	-	-	74,374	-	74,374
Operating costs and expenses	27,581	3,063	5,482	3,048	39,174
Depreciation, depletion and amortization	11,676	4,328	3,671	104	19,779
Operating income (loss)	$ 8,872	$ 16,302	$ 4,134	$ (2,891)	26,417
Interest expense and other, net					(3,121)
Unrealized loss on derivatives					(447)
Income before minority interest and taxes					$ 22,849
Total assets	$ 513,792	$ 288,278	$ 254,039	$ 20,881	$ 1,076,990
Additions to property and equipment and acquisitions, net of cash acquired (1)	$ 48,036	$ 19,659	$ 3,564	$ 57	$ 71,316
For the three months ended June 30, 2004:					
Revenues	$ 35,518	$ 18,732	$ -	$ 319	$ 54,569
Operating costs and expenses	9,076	4,264	-	2,177	15,517
Depreciation, depletion and amortization	8,426	4,852	-	109	13,387
Operating income (loss)	$ 18,016	$ 9,616	$ -	$ (1,967)	25,665
Interest expense and other, net					(1,206)
Income before minority interest and taxes					$ 24,459
Total assets	$ 444,118	$ 258,722	$ -	$ 7,108	$ 709,948
Additions to property and equipment and acquisitions, net of cash acquired	$ 33,614	$ 463	$ -	$ 37	$ 34,114

(1) Oil and gas segment includes noncash expenditures of $13.2 million.

	Oil and Gas	PVR Coal	PVR Midstream (1)	Corporate and Other	Consolidated
For the six months ended June 30, 2005:					
Revenues	$ 89,875	$ 43,505	$ 114,039	$ 535	$ 247,954
Cost of gas purchased	-	-	96,211	-	96,211
Operating costs and expenses	43,009	6,726	6,793	5,471	61,999
Depreciation, depletion and amortization	22,344	8,183	4,895	201	35,623
Operating income (loss)	$ 24,522	$ 28,596	$ 6,140	$ (5,137)	54,121
Interest expense and other, net					(6,180)
Unrealized loss on derivatives					(14,764)
Income before minority interest and taxes					$ 33,177
Total assets	$ 513,792	$ 288,278	$ 254,039	$ 20,881	$ 1,076,990
Additions to property and equipment and acquisitions, net of cash acquired (2)	$ 85,325	$ 29,031	$ 199,466	$ 65	$ 313,887
For the six months ended June 30, 2004:					
Revenues	$ 72,999	$ 36,695	$ -	$ 501	$ 110,195
Operating costs and expenses	22,187	8,270	-	4,176	34,633
Depreciation, depletion and amortization	17,708	9,621	-	214	27,543
Operating income (loss)	$ 33,104	$ 18,804	$ -	$ (3,889)	48,019
Interest expense and other, net					(2,322)
Income before minority interest and taxes					$ 45,697
Total assets	$ 444,118	$ 258,722	$ -	$ 7,108	$ 709,948
Additions to property and equipment, net of cash acquired (3)	$ 48,693	$ 1,927	$ -	$ 69	$ 50,689

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) Oil and gas segment includes noncash expenditures of $13.2 million.
(3) Coal segment includes noncash expenditures of $1.1 million.

13. RECENT ACCOUNTING PRONOUNCEMENTS

In December 2004, the Financial Accounting Standards Board (the “FASB”) issued the final revised version of SFAS No. 123R, *Share-Based Payment*, which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. In March 2005, the Securities and Exchange Commissions (the “SEC”) issued Staff Accounting Bulletin (“SAB”) No. 107, *Share-Based Payment*, regarding the interaction between SFAS No. 123R and certain SEC rules and regulations. We expect to adopt SFAS No. 123R and SAB No. 107 on January 1, 2006. At that time, we will begin to recognize compensation expense for new grants as well as the unvested portion of then outstanding options. Expense will be recognized over the requisite vesting period. We are currently assessing the effect of SFAS No. 123R on our financial statements.

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

In April 2005, the FASB issued FASB Staff Position No. FAS 19-1 (the “FSP”) to amend the guidance for suspended well costs in SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.* The FSP addresses circumstances that permit the continued capitalization of exploratory well costs beyond one year. Essentially, exploratory drilling costs may continue to be capitalized beyond one year if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The FSP is effective for the first reporting period beginning after April 4, 2005, or our third quarter beginning July 1, 2005. We do not expect the adoption of the FSP to have a material effect on future results of operations or financial position.

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

In June 2005, the EITF reached a consensus on EITF Issue No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.* This consensus applies to voting right entities not within the scope of FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities,* in which the investor is the general partner in a limited partnership or functional equivalent. The EITF consensus is that the general partner in a limited partnership is presumed to control that limited partnership regardless of the extent of the general partner’s ownership interest and, therefore, should include the limited partnership in its consolidated financial statements. The general partner may overcome this presumption of control and not consolidate the entity if the limited partners have either: (a) the substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the general partner through substantive kick-out rights that can be exercised without having to show cause; or (b) substantive participating rights in managing the partnership. This guidance became immediately effective upon ratification by the FASB on June 29, 2005, for all newly formed limited partnerships and for existing limited partnerships for which the partnership agreements have been modified. For general partners in all other limited partnerships, the guidance is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. We do not expect the adoption of this guidance to have a material impact on the consolidated financial statements.

14. SUBSEQUENT EVENTS

Wayland Acquisition

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

Green River Acquisition

In July 2005, PVR also acquired fee ownership of approximately 95 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for $62 million in cash (the “Green River Acquisition”). This coal reserve acquisition is PVR’s first in the Illinois Basin and was funded using the Partnership’s recently expanded credit facility. Currently, approximately 45 million tons of these coal reserves are leased to affiliates of Peabody Energy (NYSE:BTU). PVR expects the remaining coal reserves to be leased over the next several years, with a gradual increase in coal production and related cash flow from the property.

Dividend Declared

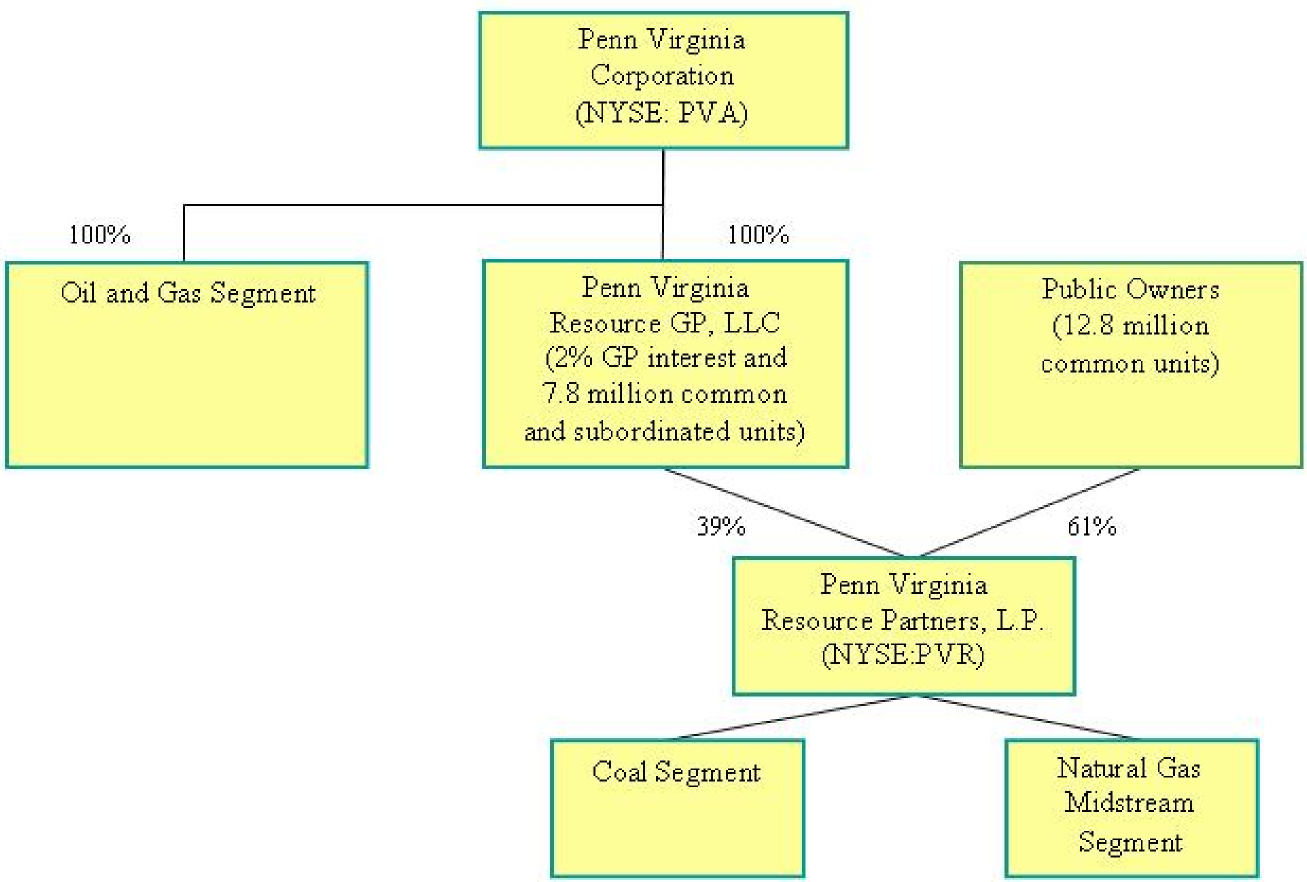
On July 27, 2005, our Board of Directors declared a quarterly dividend of $0.1125 per share payable September 1, 2005, to shareholders of record on August 11, 2005.

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

The following analysis of financial condition and results of operations of Penn Virginia Corporation and subsidiaries should be read in conjunction with our Consolidated Financial Statements and Notes thereto.

Overview

Penn Virginia Corporation ("Penn Virginia," "PVA," the "Company," "we" or "our") is an independent energy company that is engaged in three primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States. Our coal segment and natural gas midstream segment operate through our 39 percent ownership in Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"). Penn Virginia and PVR are both publicly traded on the New York Stock Exchange under the symbols PVA and PVR, respectively. Due to our control of the general partner of PVR, the financial results of the Partnership are included in our consolidated financial statements. However, PVR functions with a capital structure that is independent of the Company, consisting of its own debt instruments and publicly traded common units. The following diagram depicts our ownership of PVR and our segments as of June 30, 2005. In July 2005, PVR issued new common units in conjunction with an acquisition of coal properties (see "Wayland Acquisition – PVR Coal Segment").



As a result of our ownership interest in the Partnership, we receive cash payments from PVR in the form of quarterly cash distributions. We received approximately $5.3 million and $9.9 million of cash distributions during the three months and six months ended June 30, 2005, respectively. We received approximately $4.2 million and $8.5 million of cash distributions during the three months and six months ended June 30, 2004, respectively. As a result of our ownership of 100 percent of PVR's general partner, we also own the rights, referred to as incentive distribution rights, to receive an increasing percentage of quarterly distributions of available cash from PVR's operating surplus after certain levels of cash distributions have been achieved. PVR first achieved such a level of distribution in the first quarter of 2005. Accordingly, when PVR paid its quarterly distributions of $0.5625 per unit in February 2005 and $0.62 per unit in May 2005, the first $0.55 per unit was paid 98 percent to all units, pro rata, and two percent to the general partner. The amount in excess of $0.55 per unit was paid 85 percent to all units, pro rata, and 15 percent to the general partner.

We are committed to increasing value to our shareholders by conducting a balanced program of investment in our three business segments. In the oil and gas segment, we expect to continue to execute a program combining relatively low risk, moderate return development drilling in Appalachia, Mississippi, east Texas and north Louisiana with higher risk, higher return exploration and development drilling in the onshore Gulf Coast, supplemented periodically with acquisitions. In addition to our continuing conventional development program, we have continued to expand our presence in unconventional plays by developing coalbed methane ("CBM") gas reserves in Appalachia. By employing horizontal drilling techniques, we expect to continue to increase the value from the CBM-prospective properties we own. We are committed to expanding our oil and gas reserves and production primarily by using our ability to generate exploratory prospects and development drilling programs internally.

Oil and gas segment capital expenditures for 2005 are expected to be between approximately $166 million and $172 million. The increase in anticipated 2005 capital expenditures from our original capital expenditures budget of $146 million is primarily due to increased expenditures to expand the Company's Cotton Valley program in east Texas and north Louisiana, the horizontal CBM program in Appalachia and the Selma Chalk program in Mississippi. As of June 30, 2005, outstanding borrowings under our $150 million credit facility were $89 million, and we expect to fund our 2005 capital expenditures with a combination of internal cash flow and credit facility borrowings.

In the coal and natural gas midstream segments, PVR continually evaluates acquisition opportunities that are accretive to cash available for distribution to its unitholders, of which we are the largest single unitholder. These opportunities include, but are not limited to, acquiring additional coal properties and reserves, acquiring or constructing assets for coal services and natural gas midstream gathering and processing, all of which would provide a primarily fee-based revenue stream.

For the remainder of 2005, PVR anticipates making additional capital expenditures, excluding acquisitions, of approximately $13 million, primarily for construction of a processing plant and high speed rail loading facility on the Wayland property acquired in July 2005 and for system expansion and enhancement projects in the midstream segment. Part of PVR's strategy is to make acquisitions which increase cash available for distribution to its unitholders. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on the ability to periodically use equity financing through the issuance of new common units.

Acquisitions

Cantera Acquisition – PVR Midstream Segment

On March 3, 2005, PVR completed the acquisition (the "Cantera Acquisition") of Cantera Gas Resources LLC ("Cantera") for total cash consideration of approximately $198 million, which PVR funded with a $110 million term loan and with borrowings under its revolving credit facility. The purchase price allocation for the Cantera Acquisition has not been finalized. PVR used the proceeds from its sale of common units in a subsequent public offering in March 2005 to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. See Note 3 in the Notes to Consolidated Financial Statements for pro forma financial information.

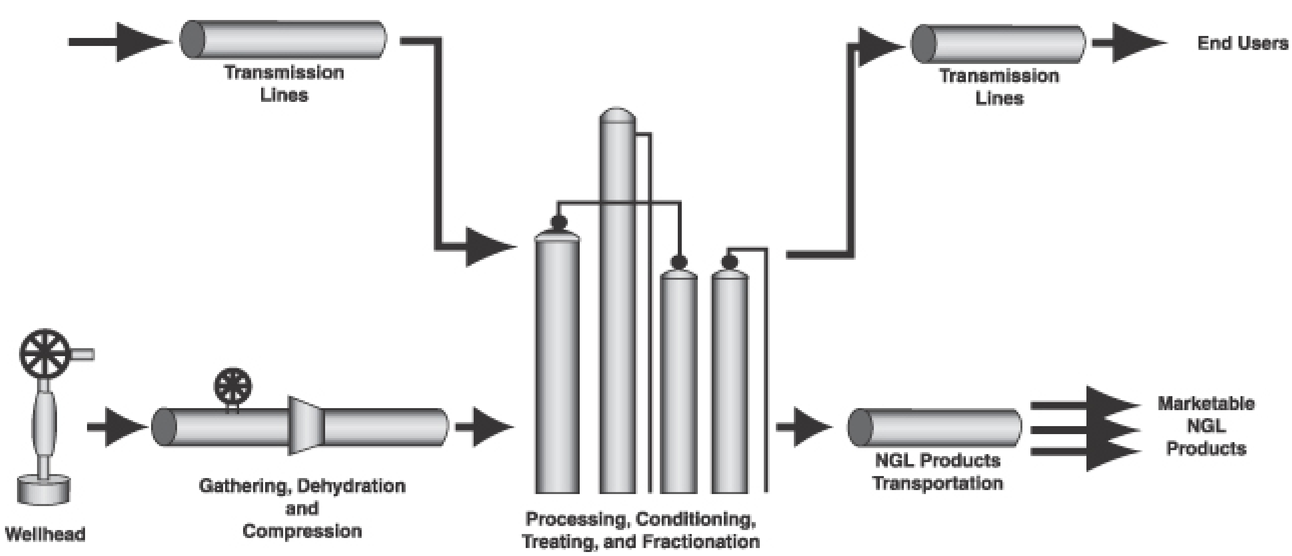
As a result of the Cantera Acquisition, PVR owns and operates a significant set of midstream assets located in the mid-continent area of Oklahoma and Texas that include approximately 3,400 miles of gas gathering pipelines and three natural gas processing facilities, which have 160 million cubic feet per day (MMcfd) of total capacity. PVR's midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. The Cantera Acquisition also includes a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems, such as Enogex and ONEOK, and at market hubs accessed by various interstate pipelines. We believe that the Cantera Acquisition established a platform for future growth in the natural gas midstream sector and has diversified PVR's cash flows into another long-lived asset base. In addition, we expect the Cantera Acquisition to be accretive to distributable cash flow on a per unit basis.

The following table sets forth information regarding PVR's midstream assets:

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

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

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



These services are described below:

- *Natural Gas Gathering*. The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, it is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from the wells and transport it to larger pipelines.
- *Natural Gas Compression*. Gathering systems are designed to maximize the total throughput from all connected wells. Specifically, lower pressure gathering systems allow wells, which produce at progressively lower field pressures as they age, to remain connected to gathering systems and continue to produce for longer periods of time. As the pressure of a well declines, it becomes more difficult to deliver

its production into a higher pressure gathering system. Field compression is typically used to lower the pressure of a gathering system.

- *Natural Gas Dehydration*. As produced, some natural gas is saturated with water, which must be removed because the combination of natural gas and water can form ice that can plug the pipeline system. Water in a natural gas stream can also cause corrosion when combined with carbon dioxide or hydrogen sulfide in natural gas and condensed water in the pipeline can raise pipeline pressure. To avoid these potential issues and to meet downstream pipeline and end-user gas quality standards, natural gas is dehydrated to remove the excess water.
- *Natural Gas Treating*. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations can be high in carbon dioxide, hydrogen sulfide or certain other contaminants. Treating plants remove contaminants from natural gas to ensure that it meets pipeline quality specifications. PVR does not currently treat natural gas.
- *Natural Gas Processing and Conditioning*. Some natural gas production does not meet pipeline quality specifications or is not suitable for commercial use and must be processed to remove the NGLs. In addition, some natural gas, while not required to be processed, can be processed to take advantage of favorable processing margins.
- *Natural Gas Fractionation*. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Isobutane is primarily used to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient in synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock. PVR does not own or operate fractionation facilities.
- *Natural Gas Transportation*. Natural gas transportation pipelines receive natural gas from gathering systems and other mainline transportation pipelines and deliver the natural gas to industrial end-users, utilities and other pipelines.

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

The ability to offer natural gas producers competitive gathering and processing arrangements and subsequent reliable service is fundamental to obtaining and keeping gas supplies for PVR's gathering systems. The primary concerns of the producer are:

- the pressure maintained on the system at the point of receipt;
- the relative volumes of gas consumed as fuel;
- the relative volumes of gas lost through leakage and operating inefficiencies;
- the accuracy in measuring volume throughout the system;
- the gathering/processing fees charged;
- the timeliness of well connects;
- the customer service orientation of the gatherer/processor; and
- the reliability of the field services provided.

PVR experiences competition in all of its midstream markets based on the producer concerns listed above. PVR's competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas.

Coal River Acquisition – PVR Coal Segment

In March 2005, PVR acquired lease rights to approximately 36 million tons of undeveloped coal reserves and royalty interests in 73 producing oil and natural gas wells for approximately $9 million (the "Coal River Acquisition"). The coal reserves are located in central Appalachia, adjacent to the Bull Creek tract on PVR's Coal River property in southern West Virginia. The oil and gas wells are located in eastern Kentucky and southwestern Virginia. The acquisition was funded with long-term debt under PVR's revolving credit facility.

The coal reserves are predominantly low sulfur and high BTU content; development will occur in conjunction with our Bull Creek reserves and loadout facility that was placed into service in 2004. The oil and gas property contains approximately 2.8 billion cubic feet equivalent of net proved oil and gas reserves and current net production of approximately 166 million cubic feet equivalent on an annualized basis.

Alloy Acquisition – PVR Coal Segment

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

Panther Acquisition – Oil and Gas Segment

In June 2005, we acquired approximately 60,000 acres of prospective CBM leasehold rights in Wyoming County, West Virginia, from Panther Energy Company, LLC, for approximately $13 million (the "Panther Acquisition"). The leasehold acreage is within an area of mutual interest between Penn Virginia and CDX Gas, LLC, ("CDX") and is contiguous to acreage which has been successfully developed. CDX has a 30-day option to purchase a 50 percent interest in the leasehold acreage, which we expect CDX to exercise. We plan to begin drilling on the new leasehold position in the fourth quarter of 2005.

Wayland Acquisition – PVR Coal Segment

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

Green River Acquisition – PVR Coal Segment

In July 2005, PVR also acquired fee ownership of approximately 95 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for approximately $62 million of cash (the "Green River Acquisition"). This coal reserve acquisition is PVR's first in the Illinois Basin and was funded using the Partnership's recently expanded credit facility. Currently, approximately 45 million tons of these coal reserves are leased to affiliates of Peabody Energy (NYSE:BTU). PVR expects the remaining coal reserves to be leased over the next several years, with a gradual increase in coal production and related cash flow from the property.

Critical Accounting Policies and Estimates

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

Reserves. The estimates of oil and gas reserves are the single most critical estimate included in our financial statements. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities including projecting the total quantities in place, future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those quantities that require additional capital investment through drilling or well recompletion techniques.

Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties subject to potential impairments.

There are several factors which could change our estimates of oil and gas reserves. Significant rises or declines in product prices could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. Additionally, we perform impairment tests pursuant to Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates.

Depreciation and depletion of oil and gas producing properties is determined by the units-of-production method and could change with revisions to estimated proved recoverable reserves.

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. The Partnership's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively.

Oil and Gas Revenues. Oil and gas sales revenues are recognized when crude oil and natural gas volumes are produced and sold for our account. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, accruals for revenues and accounts receivable are made based on estimates of our share of production, particularly from properties that are operated by our partners. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. Any differences between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Natural Gas Midstream Revenues. Revenue from the sale of NGLs and residue gas is recognized when the NGLs and residue gas produced at PVR's gas processing plants are sold. Gathering and transportation revenue is recognized based upon actual volumes delivered. Due to the time involved in gathering information from various purchasers and measurement locations and calculating volumes delivered, the collection of natural gas midstream revenues may take up to 30 days following the month of production. Therefore, accruals for revenues and accounts receivable and the related cost of gas purchased and accounts payable are made based on estimates of natural gas purchased and NGLs and natural gas sold, and our financial results include estimates of production and revenues for the period of actual production. Any differences, which are not expected to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized.

Coal Royalty Revenues. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership's lessees and the corresponding revenues from those sales. Since PVR does not operate any mines, it does not have access to actual production and revenue information until approximately 30 days following the month of production. Therefore, the financial results of the Partnership include estimated revenues and accounts receivable for this 30-day period. Any differences between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Oil and Gas Properties. We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Annual lease rentals, exploration costs, geological, geophysical and seismic costs and exploratory dry-hole costs are expensed as incurred. Pursuant to SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Reporting Companies*, costs of drilling exploratory wells are initially capitalized and later charged to expense if it is determined that the wells do not justify commercial development. Occasionally, it may be determined that oil and gas reserves were discovered when an exploratory well was drilled, but classification of those reserves as proved could not be made when drilling was completed. If classification of proved reserves cannot be made in an area requiring a major capital expenditure, the cost of drilling the exploratory well is carried as an asset provided that (a) there have been sufficient reserves found to justify completion as a producing well if the required capital expenditure is made and (b) further well completion work needs to be performed or additional exploratory wells need to be drilled and those activities are either underway or firmly planned for the near future. If either of these two criteria is not met, exploratory well costs are expensed. For all other exploratory wells, costs of exploratory wells are expensed if the reserves cannot be classified as proved after one year following the completion of drilling.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At June 30, 2005, the costs attributable to unproved properties were approximately $67.4 million. These costs are not currently being depreciated or depleted. As exploration work progresses and the reserves on these properties are proven, capitalized costs of the properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations. In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, we make estimates of the timing and future costs of plugging and abandoning wells. Estimated abandonment dates will be revised in the future based on changes to related economic lives, which vary with product prices and production costs. Estimated plugging costs may also be adjusted to reflect changing industry experience. Our cash flows would not be affected until plugging and abandoning wells actually occurred.

Results of Operations

Selected Financial Data – Consolidated

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
	(in thousands, except share data)		(in thousands, except share data)	
Revenues	$ 159,744	$ 54,569	$ 247,954	$ 110,195
Operating expenses	$ 133,327	$ 28,904	$ 193,833	$ 62,176
Operating income	$ 26,417	$ 25,665	$ 54,121	$ 48,019
Net income	$ 7,647	$ 12,080	$ 14,687	$ 22,222
Earnings per share, basic	$ 0.41	$ 0.66	$ 0.79	$ 1.22
Earnings per share, diluted	$ 0.41	$ 0.65	$ 0.79	$ 1.21
Cash flows provided by operating activities	$ 53,815	$ 34,055	$ 84,666	$ 58,599

Net income for the Company totaled $14.7 million for the six months ended June 30, 2005, a decrease of 34 percent from the six months of June 30, 2004. The decrease in net income was primarily attributable to an $8.0 million (after tax) write-off of unproved property and drilling costs related to an unsuccessful exploratory well in south Texas in the second quarter of 2005 and a one-time $3.6 million non-cash charge to earnings, after taxes and minority interest, for an unrealized loss on derivatives in the first half of 2005. These decreases in net income were partially offset by the contribution of a natural gas midstream business that was acquired in the first quarter of 2005 and increased natural gas production at higher realized prices.

The assets, liabilities and earnings of PVR are fully consolidated in our financial statements, with the public unitholders' interest reflected as a minority interest.

Oil and Gas Segment

In our oil and gas segment, we explore for, develop, produce and sell crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore regions of the United States. Our revenues, profitability and future rate of growth are highly dependent on the prevailing prices for oil and natural gas, which are affected by numerous factors that are generally beyond our control. Crude oil prices are generally determined by global supply and demand. Natural gas prices are influenced by national and regional supply and demand. A substantial or extended decline in the prices of oil or natural gas could have a material adverse effect on our revenues, profitability and cash flow and could, under certain circumstances, result in an impairment of our oil and natural gas properties. Our future profitability and growth is also highly dependent on the results of our exploratory and development drilling programs.

Operations and Financial Summary – Oil and Gas Segment

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

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	% Change	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004
	(in thousands, except as noted)			(per MMcfe)*	
Production					
Natural gas (MMcf)	6,438	5,294	22 %		
Oil and condensate (Mbbls)	76	94	(19)%		
Total production (MMcfe)	6,894	5,858	18 %		
Revenues					
Natural gas					
Revenue received for production	$ 45,254	$ 33,189	36 %	$ 7.03	$ 6.27
Effect of hedging activities	(574)	(745)	(23)%	(0.09)	(0.14)
Net revenue realized	44,680	32,444	38 %	6.94	6.13
Oil and condensate					
Revenue received for production	3,444	3,487	(1)%	45.32	37.09
Effect of hedging activities	(98)	(457)	(79)%	(1.29)	(4.86)
Net revenue realized	3,346	3,030	10 %	44.03	32.23
Other income	103	44	134 %		
Total revenues	48,129	35,518	36 %	6.98	6.06
Expenses					
Operating	3,954	3,271	21 %	0.57	0.56
Taxes other than income	3,246	2,147	51 %	0.47	0.37
General and administrative	2,450	1,823	34 %	0.36	0.31
Production costs	9,650	7,241	33 %	1.40	1.24
Exploration	17,931	1,835	877 %	2.60	0.31
Depreciation, depletion and amortization	11,676	8,426	39 %	1.69	1.44
Total expenses	39,257	17,502	124 %	5.69	2.99
Operating income	$ 8,872	$ 18,016	(51)%	$ 1.29	$ 3.07

*Natural gas revenues are shown per million cubic feet ("Mcf"), oil and condensate revenues are shown per barrel ("Bbl"), and all other amounts are shown per Mcfe.

Production. Second quarter 2005 production was greater than second quarter 2004 production due to new production from drilling, including the horizontal CBM project in Appalachia and the Cotton Valley play in east Texas and north Louisiana, partially offset by the first quarter 2005 sale of oil and gas properties in West Texas and normal field decline.

Revenues. Approximately 93 percent and 90 percent of production in the three months ended June 30, 2005 and 2004, respectively, was natural gas. Increased natural gas production accounted for approximately $7.0 million, or 57 percent, of the increase in natural gas revenues. Increased realized prices for natural gas accounted for approximately $5.2 million, or 43 percent, of the increase in natural gas revenues. The average realized price received for natural gas during the second quarter of 2005 was $6.94 per Mcf compared with $6.13 per Mcf in the second quarter of 2004, a 13 percent increase. The average realized oil price received was $44.03 per barrel for the second quarter of 2005, up 37 percent from $32.23 per barrel in the second quarter of 2004. This price increase for crude oil was partially offset by a decline in oil production for the second quarter of 2005 compared to the second quarter of 2004 due to the sale of oil and gas properties in West Texas and normal field decline.

Due to the volatility of crude oil and natural gas prices, we hedge the price received for certain sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In the second quarter of 2005, approximately 41 percent of our natural gas was hedged using costless collars at an average floor price of $5.48 per MMbtu and an average ceiling price of $7.53 per MMbtu. We also hedged approximately 32 percent of our crude oil production using costless collars with an average floor price of $42.00 per barrel and an average ceiling price of $47.75. We recognized a loss on settled hedging activities of $0.7 million in the second quarter of 2005, compared with a loss of $1.2 million in the second quarter of 2004.

Operating Expenses. The oil and gas segment's aggregate operating costs and expenses in the second quarter of 2005 increased primarily due to higher exploration expenses and higher depreciation, depletion and amortization ("DD&A") expense.

Exploration expenses for the three months ended June 30, 2005 and 2004, consisted of the following (in thousands):

	Three Months Ended June 30,	
	2005	**2004**
Dry hole costs	$ 3,695	$ 16
Seismic	1,136	781
Unproved leasehold write-offs	12,782	948
Other	318	90
Total	$ 17,931	$ 1,835

Exploration expenses increased primarily due to higher unproved leasehold write-offs and dry hole costs for an unsuccessful exploratory well in south Texas. The balance of the increase in exploration expenses was primarily due to unproved leasehold write-offs relating to expired lease options.

Oil and gas DD&A increased due to the 18 percent increase in equivalent production and as a result of higher average depletion rates. The average depletion rate increased from $1.44 per Mcfe in the second quarter of 2004 to $1.69 per Mcfe in the second quarter of 2005 as a result of a greater percentage of production coming from relatively higher cost horizontal CBM wells and wells in our Bethany development drilling joint venture combined with depreciation on new pipeline infrastructure placed in service during the fourth quarter of 2004.

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

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	% Change	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(in thousands, except as noted)			(per MMcfe)*	
Production					
Natural gas (MMcf)	12,353	11,053	12 %		
Oil and condensate (Mbbls)	161	210	(23)%		
Total production (MMcfe)	13,319	12,313	8 %		
Revenues					
Natural gas					
Revenue received for production	$ 83,566	$ 68,171	23 %	$ 6.76	$ 6.17
Effect of hedging activities	(626)	(1,763)	(64)%	(0.05)	(0.16)
Net revenue realized	82,940	66,408	25 %	6.71	6.01
Oil and condensate					
Revenue received for production	7,107	7,235	(2)%	44.14	34.45
Effect of hedging activities	(348)	(717)	(51)%	(2.16)	(3.41)
Net revenue realized	6,759	6,518	4 %	41.98	31.04
Other income	176	73	141 %		
Total revenues	89,875	72,999	23 %	6.75	5.93
Expenses					
Operating	7,076	6,216	14 %	0.53	0.50
Taxes other than income	6,060	4,959	22 %	0.45	0.40
General and administrative	4,283	3,617	18 %	0.32	0.29
Production costs	17,419	14,792	18 %	1.30	1.19
Exploration	25,590	7,395	246 %	1.92	0.60
Depreciation, depletion and amortization	22,344	17,708	26 %	1.68	1.44
Total expenses	65,353	39,895	64 %	4.90	3.23
Operating income	$ 24,522	$ 33,104	(26)%	$ 1.85	$ 2.70

*Natural gas revenues are shown per million cubic feet ("Mcf"), oil and condensate revenues are shown per barrel ("Bbl"), and all other amounts are shown per Mcfe.

Production. Production for the six months ended June 30, 2005, was greater than production for the six months ended June 30, 2004, due to new production from drilling, including the horizontal CBM project in Appalachia and the Cotton Valley play in east Texas and north Louisiana, partially offset by the first quarter 2005 sale of oil and gas properties in West Texas and normal field decline.

Revenues. Approximately 94 percent and 90 percent of production in the six months ended June 30, 2005 and 2004, respectively, was natural gas. Increased natural gas production accounted for approximately $7.8 million, or 47 percent, of the increase in natural gas revenues. Increased realized prices for natural gas accounted for approximately $8.7 million, or 53 percent, of the increase in natural gas revenues. The average realized price received for natural gas during the first half of 2005 was $6.71 per Mcf compared with $6.01 per Mcf in the same period of 2004, a 12 percent increase. The average realized oil price received was $41.98 per barrel for the six months ended June 30, 2005, up 35 percent from $31.04 per barrel in the same period of 2004. This price increase for crude oil was partially offset by a decline in oil production for the six months ended June 30, 2005, compared to the same period of 2004 due to the sale of oil and gas properties in West Texas and normal field decline.

Due to the volatility of crude oil and natural gas prices, we hedge the price received for certain sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In the six months ended June 30, 2005, approximately 42 percent of our natural gas was hedged using costless collars at an average floor price of $5.45 per MMbtu and an average ceiling price of $7.74 per MMbtu. We also hedged approximately 30 percent of our crude oil production using fixed price swaps with an average price of $30.13 that expired in January 2005 and costless collars with an average floor price of $42.00 per barrel and an average ceiling price of $47.75. We recognized a loss on settled hedging activities of $1.0 million in the six months ended June 30, 2005, compared with a loss of $2.5 million in the same period of 2004.

Operating Expenses. The oil and gas segment's aggregate operating costs and expenses in the six months ended June 30, 2005, increased primarily due to higher exploration expenses and higher DD&A expense.

Exploration expenses for the six months ended June 30, 2005 and 2004, consisted of the following (in thousands):

	Six Months Ended June 30,	
	2005	**2004**
Dry hole costs	$ 5,865	$ 439
Seismic	5,996	4,577
Unproved leasehold write-offs	13,051	2,207
Other	678	172
Total	$ 25,590	$ 7,395

Exploration expenses increased primarily due to higher unproved leasehold write-offs and dry hole costs for an unsuccessful exploratory well in south Texas. The balance of the increase in exploration expenses was primarily due to unproved leasehold write-offs relating to expired lease options.

Oil and gas DD&A increased due to the eight percent increase in equivalent production and as a result of higher average depletion rates. The average depletion rate increased from $1.44 per Mcfe in the six months ended June 30, 2004, to $1.68 per Mcfe in the same period of 2005 as a result of a greater percentage of production coming from relatively higher cost horizontal CBM wells and wells in our Bethany development drilling joint venture combined with depreciation on new pipeline infrastructure placed in service during the fourth quarter of 2004.

PVR Coal Segment

The PVR coal segment includes coal reserves, coal services, timber and other land assets. The Partnership enters into leases with various third-party operators for the right to mine coal reserves on the Partnership's properties in exchange for royalty payments. The Partnership does not operate any mines. Approximately 82 percent of the Partnership's coal royalty revenues for the first six months of 2005 and 78 percent of its coal royalty revenues for the first six months of 2004 were derived from coal mined on the Partnership's properties and sold by its lessees under leases providing for royalty rates per ton leased on the higher of a percentage of the gross sales price or a fixed price per ton of coal, with pre-established minimum monthly or annual rental payments. The balance of the Partnership's coal royalty revenues for the first six months of 2005 and the first six months of 2004 was derived from coal mined on two of the Partnership's properties under leases containing fixed royalty rates per ton of coal mined and sold. The royalty rates under those leases escalate annually, with pre-established minimum monthly payments. In addition to coal royalty revenues, the Partnership generates coal services revenues from fees charged to lessees for the use of coal preparation and transloading facilities. The Partnership also generates revenues from the sale of standing timber on its properties.

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

Operations and Financial Summary – PVR Coal Segment

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

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	% Change
	(in thousands, except as noted)		
Revenues			
Coal royalties	$ 20,129	$ 17,517	15 %
Coal services	1,338	942	42 %
Timber	117	142	(18)%
Other	2,109	131	1,510 %
Total revenues	23,693	18,732	26 %
Expenses			
Operating	1,141	2,048	(44)%
Taxes other than income	230	230	-
General and administrative	1,692	1,986	(15)%
Operating expenses before non-cash charges	3,063	4,264	(28)%
Depreciation, depletion and amortization	4,328	4,852	(11)%
Total expenses	7,391	9,116	(19)%
Operating income	$ 16,302	$ 9,616	70 %
Production			
Royalty coal tons produced by lessees (thousands)	7,250	7,941	(9)%
Prices			
Royalty per ton	$ 2.78	$ 2.21	26 %

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

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

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

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

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

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

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

Other revenues increased primarily due to $1.5 million received during the second quarter of 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents. PVR also began receiving additional transportation-related fees in the second quarter of 2005 as a result of the Alloy Acquisition in April 2005.

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

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

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

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

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	% Change
	(in thousands, except as noted)		
Revenues			
Coal royalties	$ 38,182	$ 34,377	11 %
Coal services	2,608	1,726	51 %
Timber	336	295	14 %
Other	2,379	297	701 %
Total revenues	43,505	36,695	19 %
Expenses			
Operating	2,173	3,797	(43)%
Taxes other than income	508	514	(1)%
General and administrative	4,045	3,959	2 %
Operating expenses before non-cash charges	6,726	8,270	(19)%
Depreciation, depletion and amortization	8,183	9,621	(15)%
Total expenses	14,909	17,891	(17)%
Operating income	$ 28,596	$ 18,804	52 %
Production			
Royalty coal tons produced by lessees (thousands)	13,965	15,894	(12)%
Prices			
Royalty per ton	$ 2.73	$ 2.16	26 %

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

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

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

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

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

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

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

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

Other revenues increased primarily due to $1.5 million received during the second quarter of 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents. PVR also began receiving additional transportation-related fees in the second quarter of 2005 as a result of the Alloy Acquisition in April 2005.

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

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

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

PVR Midstream Segment

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

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

Operations and Financial Summary – PVR Midstream Segment

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

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

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

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

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

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

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

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

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

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

Corporate and Other Segment

The corporate and other segment primarily consists of oversight and administrative functions.

Operations and Financial Summary – Corporate and Other Segment

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

	Three Months Ended June 30,	
	2005	**2004**
	(in thousands, except as noted)	
Revenues		
Other	$ 261	$ 319
Total revenues	261	319
Expenses		
Operating	133	150
Taxes other than income	92	87
General and administrative	2,823	1,940
Operating expenses before non-cash charges	3,048	2,177
Depreciation, depletion and amortization	104	109
Total expenses	3,152	2,286
Operating loss	(2,891)	(1,967)
Interest expense and other, net	(3,121)	(1,206)
Unrealized loss on derivatives	(447)	-
Contribution to income from operations before minority interest and income taxes	$ (6,459)	$ (3,173)

General and administrative (G&A) expenses increased due to expenses related to compliance with the Sarbanes-Oxley Act of 2002 and a general increase in staffing levels.

Interest expense increased primarily due to interest incurred on additional borrowings on PVR's revolving credit facility and a new term loan in March 2005 to finance the Cantera Acquisition. Sixty-six percent and 100 percent of PVA's direct credit facility interest costs were capitalized during the three months ended June 30, 2005 and 2004, respectively, because the borrowings funded the preparation of unproved properties for their intended use. We capitalized interest costs amounting to $0.7 million and $0.4 million in the quarters ended June 30, 2005 and 2004, respectively.

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

	Six Months Ended June 30,	
	2005	2004
	(in thousands, except as noted)	
Revenues		
Other	$ 535	$ 501
Total revenues	535	501
Expenses		
Operating	283	300
Taxes other than income	243	21
General and administrative	4,945	3,855
Operating expenses before non-cash charges	5,471	4,176
Depreciation, depletion and amortization	201	214
Total expenses	5,672	4,390
Operating loss	(5,137)	(3,889)
Interest expense and other, net	(6,180)	(2,322)
Unrealized loss on derivatives	(14,764)	-
Contribution to income from operations before minority interest and income taxes	$ (26,081)	$ (6,211)

Taxes other than income increased due to a franchise tax adjustment in the first quarter of 2004.

General and administrative (G&A) expenses increased due to expenses related to compliance with the Sarbanes-Oxley Act of 2002 and a general increase in staffing levels.

Interest expense increased primarily due to interest incurred on additional borrowings on PVR's revolving credit facility and a new term loan in March 2005 to finance the Cantera Acquisition. Seventy percent and 100 percent of PVA's direct credit facility interest costs were capitalized during the six months ended June 30, 2005 and 2004, respectively, because the borrowings funded the preparation of unproved properties for their intended use. We capitalized interest costs amounting to $1.3 million and $0.9 million in the six months ended June 30, 2005 and 2004, respectively.

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

Capital Resources and Liquidity

Although results are consolidated for financial reporting, the Company and PVR operate with independent capital structures. The Company and PVR have separate credit facilities, and neither entity guarantees the debt of the other. Since PVR's inception in 2001, with the exception of cash distributions received by the Company from PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and issuance of new partnership units. We expect that our cash needs and the cash needs of PVR will continue to be met independently of each other with a combination of these funding sources. Summarized cash flow statements for the six months ended June 30, 2005 and 2004, consolidating the oil and gas segment (and corporate) and PVR's coal and midstream segments are set forth below.

For the six months ended June 30, 2005 (in thousands)	Oil and Gas and Corporate	PVR Coal and PVR Midstream	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 293	$ 14,394	$ 14,687
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	55,185	26,799	81,984
Net change in operating assets and liabilities	(10,590)	(1,415)	(12,005)
Net cash provided by operating activities	44,888	39,778	84,666
Cash flows from investing activities:			
Acquisitions, net of cash acquired	-	(222,677)	(222,677)
Additions to property and equipment	(72,140)	(5,820)	(77,960)
Other	10,699	52	10,751
Net cash used in investing activities	(61,441)	(228,445)	(289,886)
Cash flows from financing activities:			
PVA dividends paid	(4,163)	-	(4,163)
PVR distributions received (paid)	9,922	(23,678)	(13,756)
PVA debt proceeds, net of repayments	13,000	-	13,000
PVR debt proceeds, net of repayments	-	86,000	86,000
Proceeds received from (paid for) the issuance of partners' capital	(2,570)	129,006	126,436
Other	557	(2,039)	(1,482)
Net cash provided by financing activities	16,746	189,289	206,035
Net increase in cash and cash equivalents	193	622	815
Cash and cash equivalents—beginning of period	4,474	20,997	25,471
Cash and cash equivalents—end of period	$ 4,667	$ 21,619	$ 26,286

For the six months ended June 30, 2004 (in thousands)	Oil and Gas and Corporate	PVR Coal	Consolidated
Cash flows from operating activities:			
Net income contribution	$ 17,717	$ 4,505	$ 22,222
Adjustments to reconcile net income to net cash provided by operating activities (summarized)	29,443	19,044	48,487
Net change in operating assets and liabilities	(14,694)	2,584	(12,110)
Net cash provided by operating activities	32,466	26,133	58,599
Cash flows from investing activities:			
Additions to property and equipment	(48,762)	(867)	(49,629)
Other	248	375	623
Net cash used in investing activities	(48,514)	(492)	(49,006)
Cash flows from financing activities:			
PVA dividends paid	(4,111)	-	(4,111)
PVR distributions received (paid)	8,490	(19,269)	(10,779)
PVA debt repayments, net of proceeds	(1,000)	-	(1,000)
PVR debt repayments	-	(1,000)	(1,000)
Other	3,803	-	3,803
Net cash provided by (used in) financing activities	7,182	(20,269)	(13,087)
Net increase, (decrease) in cash and cash equivalents	(8,866)	5,372	(3,494)
Cash and cash equivalents—beginning of period	8,942	9,066	18,008
Cash and cash equivalents—end of period	$ 76	$ 14,438	$ 14,514

Except where noted, the following discussion of cash flows and contractual obligations relates to consolidated results of the Company.

Cash Flows from Operating Activities

The oil and gas and corporate segments' net cash provided by operations increased primarily due to increased natural gas production and increased prices received for natural gas and crude oil. We used cash from operating activities during both years to help fund the respective year's capital expenditures. Cash provided by operations of the coal segment increased primarily due to an increase in average royalties per ton resulting from higher coal sales prices. PVR's acquisition of its natural gas midstream segment was accretive to operating cash flows in the first half of 2005.

Cash Flows from Investing Activities

During the six months ended June 30, 2005 and 2004, we used cash primarily for capital expenditures for oil and gas development and exploration activities and acquisitions of oil and gas properties as well as the acquisition of seismic data. During the first quarter of 2005, PVR acquired Cantera for approximately $198 million, net of cash acquired. PVR also acquired two coal properties and oil and gas royalty interests for $25 million.

Capital expenditures totaled $318.4 million for the six months ended June 30, 2005, compared with $57.5 million during the same period in 2004. The following table sets forth capital expenditures by segment, made during the periods indicated:

	Six Months Ended June 30,	
	2005	**2004**
	(in thousands)	
Oil and gas		
Development drilling	$ 48,440	$ 35,142
Exploration drilling	10,679	3,992
Seismic	6,079	4,547
Lease acquisition and other	19,932	6,201
Pipeline, gathering, facilities	4,678	5,606
Total	89,808	55,488
Coal		
Lease acquisitions *	24,721	1,132
Support equipment and facilities	4,310	795
Total	29,031	1,927
Natural gas midstream		
Acquisitions, net of cash acquired	197,956	-
Other property and equipment expenditures	1,510	-
Total	199,466	-
Other	65	69
Total capital expenditures	$ 318,370	$ 57,484

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

We are committed to expanding our oil and natural gas operations over the next several years through a combination of exploration, development and acquisition of new properties. We have a portfolio of assets which balances relatively low risk, moderate return development projects in Appalachia and Mississippi with relatively moderate risk, potentially higher return development projects and exploration prospects in south Texas and south Louisiana.

Oil and gas segment capital expenditures for 2005 are expected to be between approximately $166 million and $172 million. The increase in anticipated 2005 capital expenditures from our original capital expenditures budget of $146 million is primarily due to increased expenditures to expand the Cotton Valley program in east Texas and north Louisiana, the horizontal CBM program in Appalachia and the Selma Chalk program in Mississippi. As of June 30, 2005, outstanding borrowings under our $150 million credit facility were $89 million, and we expect to fund our 2005 capital expenditures with a combination of internal cash flow and credit facility borrowings.

During the first six months of 2005, PVR made capital expenditures of approximately $9 million for the Coal River Acquisition, $15 million for the Alloy Acquisition and $198 million for the Cantera Acquisition. All acquisitions were initially funded using credit facility borrowings. Funding of the Cantera Acquisition is further described in the following section, "Cash Flows from Financing Activities."

Cash Flows from Financing Activities

Consolidated net cash provided by financing activities was $206 million for the six months ended June 30, 2005, compared with $13.1 million used in financing activities for the same period in 2004. PVR had borrowings, net of repayments, of $86 million in the six months ended June 30, 2005, to finance the Cantera Acquisition, compared to $1 million in net repayments by PVR in the same period of 2004. During the six months ended June 30, 2005, we borrowed $13 million on PVA's credit facility, net of repayments. During the six months ended June 30, 2004, $1 million of borrowings under PVA's credit facility were repaid, net of proceeds from additional borrowings. PVR received proceeds of $126.4 million, net of a $2.5 million contribution by the general partner, from the sale of its common units in a public offering which was completed in March 2005. In the six months ended June 30, 2005 and 2004, we received $9.9 million and $8.5 million of cash distributions, respectively, from PVR. These distributions were primarily used for capital expenditure needs.

In July 2005, PVR announced a $0.03 per unit, or five percent, increase in its quarterly distribution from $0.62 per unit paid in May 2005 to $0.65 per unit payable August 12, 2005, to unitholders of record on August 2, 2005. As a result of the 7.8 million limited partner units and incentive distribution rights we own as PVR's general partner, cash distributions we receive from PVR are expected to increase from $5.3 million in the second quarter of 2005 to approximately $5.6 million in each of the third and fourth quarters of 2005.

As of June 30, 2005, we had outstanding borrowings of $89 million under our revolving credit facility which has an initial commitment of $150 million and which can be expanded at our option to our current approved borrowing base of $200 million. We also have a $5 million line of credit, which had no borrowings against it as of June 30, 2005. The line of credit is effective through June 2005 and is renewable annually in June. The financial covenants in our credit agreements require us to maintain certain levels of debt-to-earnings and dividend limitation restrictions. At June 30, 2005, we were in compliance with all of our covenants.

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

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

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

Concurrent with the closing of the Cantera Acquisition, PVR entered into a new unsecured $260 million, five-year credit agreement. As of June 30, 2005, the new credit agreement consisted of a $150 million revolving credit facility. A portion of the revolving credit facility and a $110 million term loan were used to fund the Cantera Acquisition and to repay borrowings under PVR's previous credit facility. The revolving credit facility is available for general Partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. As of June 30, 2005, PVR had a one-time option under the revolving credit facility to increase the facility by an additional $100 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders. Proceeds received from the March 2005 public offering of PVR common units were used to repay the $110 million term loan and a portion of the amount outstanding under the revolving credit facility. The term loan cannot be re-borrowed.

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

Future Capital Needs and Commitments. For the year ending December 31, 2005, we anticipate making total capital expenditures in our oil and gas segment, excluding acquisitions, of between approximately $166 and $172 million. These expenditures are expected to be funded primarily by operating cash flow. Additional funding will be provided as needed from our revolving credit facility, under which we had $61 million of borrowing capacity as of June 30, 2005.

In the coal and natural gas midstream segments, over the remaining five months of 2005, PVR anticipates making total capital expenditures, excluding acquisitions, of approximately $15 million primarily for construction of a processing plant and high speed rail loading facility on the Wayland property acquired in July 2005 and for midstream system expansion projects. Part of PVR's strategy is to make acquisitions which increase cash available for distribution to its unitholders. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new partnership common units.

Environmental Matters

Our businesses are subject to various environmental hazards. Numerous federal, state and local laws, regulations and rules govern the environmental aspects of our businesses. Noncompliance with these laws, regulations and rules can result in substantial penalties or other liabilities. We do not believe our environmental risks are materially different from those of comparable companies or that cost of compliance will have a material adverse effect on our profitability, capital expenditures, cash flows or competitive position.

However, there is no assurance that future changes in or additions to laws, regulations or rules regarding the protection of the environment will not have such an impact. We believe we are materially in compliance with environmental laws, regulations and rules.

In conjunction with the Partnership's leasing of property to coal operators, environmental and reclamation liabilities are generally the responsibilities of the Partnership's lessees. Lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary.

Recent Accounting Pronouncements

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Interest Rate Risk. At June 30, 2005, we had $89 million of long-term debt borrowed under PVA's credit facility. The credit facility matures in December 2007 and is governed by a borrowing base calculation that is re-determined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.25 percent to 2.00 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin ranging from 0.30 percent to 0.50 percent. As a result, our 2005 interest costs will fluctuate based on short-term interest rates relating to our credit facility.

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

Price Risk Management. Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts and swaps) to mitigate the price risks associated with fluctuations in natural gas and crude oil prices as they relate to our anticipated production. These financial instruments are designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 139. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets are significantly affected by energy price fluctuations. See the discussion and table in Note 6 in the Notes to Consolidated Financial Statements for a description of our hedging program and a listing of open derivative agreements and their fair value as of June 30, 2005.

When PVR agreed to acquire Cantera, management wanted to ensure an acceptable return on the investment. This objective was supported by entering into pre-closing commodity price derivative agreements covering approximately 75 percent of the net volume of NGLs expected to be sold from April 2005 through December 2006. Rising commodity prices resulted in an increase in the market value of those derivative agreements before they qualified for hedge accounting. This change in market value resulted in a $13.9 million non-cash charge to earnings for the unrealized loss on derivatives. Subsequent to the Cantera Acquisition, PVR evaluated the effectiveness of the derivative agreements in relation to the underlying commodities and designated the agreements as cash flow hedges in accordance with SFAS No. 133. Upon qualifying for hedge accounting, changes in the derivative agreements' market value are accounted for as other comprehensive income or loss to the extent they are effective, rather than as a direct impact on net income. SFAS No. 133 requires the Partnership to continue to measure the effectiveness of the derivative agreements in relation to the underlying commodity being hedged, and it will be required to record the ineffective portion of the agreements in net income for the respective period. Cash settlements with the counterparties to the derivative agreements will occur monthly over the life of the agreements, with PVR receiving a correspondingly higher or lower amount for the physical sale of the commodity over the same period. Several derivative agreements for ethane, propane, crude oil and natural gas entered into subsequent to the Cantera Acquisition have been designated as cash flow hedges. See Note 6 in the Notes to Consolidated Financial Statements for a description of PVR's hedging program and a listing of open derivative agreements and their fair value.

Forward-Looking Statements

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

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, we caution you that assumed facts or bases almost always vary from actual results, and the differences between assumed facts or bases and actual results can be material, depending on the circumstances. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report and the documents we have incorporated by reference. These statements reflect our current views with respect to future events and are subject to various risks, uncertainties and assumptions including, but not limited, to the following:

- the cost of finding and successfully developing oil and gas reserves;
- our ability to acquire new oil and gas reserves and the price for which such reserves can be acquired;
- energy prices generally and the specific and relative prices of crude oil, natural gas, NGLs and coal;
- the volatility of commodity prices for crude oil, natural gas, NGLs and coal;
- the projected supply of and demand for crude oil, natural gas, NGLs and coal;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production;
- availability of required drilling rigs, materials and equipment;
- non-performance by third party operators in wells in which we own an interest;

- competition among producers in the oil and natural gas, coal and natural gas midstream industries generally;
- the extent to which the amount and quality of actual production of our oil and natural gas or PVR’s coal differs from estimated recoverable proved oil and gas reserves and coal reserves;
- PVR’s ability to make cash distributions to its general partner and its unitholders;
- hazards or operating risks incidental to our business and to PVR’s coal or midstream business;
- PVR’s ability to integrate and manage its new midstream business;
- PVR’s ability to continually find and contract for new sources of natural gas supply for its midstream business;
- PVR’s ability to retain its existing or acquire new midstream customers;
- PVR’s ability to acquire new coal reserves and the price for which such reserves can be acquired;
- PVR’s ability to lease new and existing coal reserves;
- the ability of PVR’s lessees to produce sufficient quantities of coal on an economic basis from PVR’s reserves;
- unanticipated geological problems;
- the occurrence of unusual weather or operating conditions including force majeure events;
- the failure of equipment or processes to operate in accordance with specifications or expectations;
- delays in anticipated start-up dates of our oil and natural gas production and PVR’s lessees’ mining operations;
- environmental risks affecting the drilling and producing of oil and gas wells, the mining of coal reserves or the production, gathering and processing of natural gas;
- the timing of receipt of necessary governmental permits by us and by PVR or PVR’s lessees;
- the risks associated with having or not having price risk management programs;
- labor relations and costs;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions (including the impact of potential terrorist attacks);
- the experience and financial condition of PVR’s coal lessees and midstream customers;
- changes in financial market conditions; and
- other risk factors as detailed in the our Annual Report on Form 10-K for the year ended December 31, 2004.

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

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

Item 4. Controls and Procedures

(a) Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company's financial reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

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

(b) Changes in Internal Control over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except that we are in the process of evaluating the controls in the newly acquired natural gas midstream business and integrating the segment into our existing internal control structure.

PART II. Other Information

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

Item 6. Exhibits

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

31.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

PENN VIRGINIA CORPORATION

Date: August 4, 2005

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

Date: August 4, 2005

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

Exhibit 12

Penn Virginia Corporation and Subsidiaries
Statement of Computation of Ratio of Earnings to Fixed Charges Calculation
(in thousands, except ratios)

	2000	2001	2002	2003	2004	Six Months Ended June 30, 2005
Earnings						
Pre-tax income*	$ 59,230	$ 54,271	$ 29,705	$ 55,987	$ 72,779	$ 31,326
Fixed charges	8,363	4,058	4,068	8,379	11,067	8,934
Total earnings	**$ 67,593**	**$ 58,329**	**$ 33,773**	**$ 64,366**	**$ 83,846**	**$ 40,260**
Fixed charges						
Interest expense**	$ 7,926	$ 3,596	$ 3,125	$ 7,352	$ 9,679	8,182
Rental interest factor	437	462	943	1,027	1,388	752
Total fixed charges	**$ 8,363**	**$ 4,058**	**$ 4,068**	**$ 8,379**	**$ 11,067**	**$ 8,934**
Ratio of earnings to fixed charges	**8.1x**	**14.4x**	**8.3x**	**7.7x**	**7.6x**	**4.5x**

* Excludes equity earnings from investees and includes capitalized interest.
** Includes capitalized interest.

Exhibit 31.1

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

I, A. James Dearlove, President and Chief Executive Officer of Penn Virginia Corporation (the "Registrant"), certify that:

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

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: August 4, 2005

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

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

I, Frank A. Pici, Executive Vice President and Chief Financial Officer of Penn Virginia Corporation (the "Registrant"), certify that:

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

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

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

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

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

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: August 4, 2005

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

Exhibit 32.1

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

In connection with the Quarterly Report of Penn Virginia Corporation (the “Company”) on Form 10-Q for the period ended June 30, 2005, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, A. James Dearlove, President and Chief Executive Officer of the Company, 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 Company.

Date: August 4, 2005

/s/ A. James Dearlove
A. James Dearlove
President and 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 Penn Virginia Corporation and will be retained by Penn Virginia Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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

In connection with the Quarterly Report of Penn Virginia Corporation (the "Company") on Form 10-Q for the period ended June 30, 2005, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Pici, Executive Vice-President and Chief Financial Officer of the Company, 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 Company.

Date: August 4, 2005

/s/ Frank A. Pici
Frank A. Pici
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 Penn Virginia Corporation and will be retained by Penn Virginia Corporation and furnished to the Securities and Exchange Commission or its staff upon request.