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 period ended June 30, 2003

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 Offices) (Zip Code)

(610) 687-8900

(Registrant's Telephone Number, Including Area Code)

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

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

Yes __X__ No ______

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

Yes __X__ No ______

As of August 5, 2003, 8,989,170 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 share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Revenues:				
Natural gas	$ 25,904	$ 15,683	$ 55,904	$ 27,020
Oil and condensate	4,314	1,875	8,627	3,869
Coal royalties	12,247	6,693	23,698	15,184
Timber	193	499	749	1,081
Other	1,045	898	2,741	2,877
Total revenues	**43,703**	**25,648**	**91,719**	**50,031**
Expenses:				
Lease operating	4,282	2,568	7,873	5,382
Exploration	3,712	2,026	7,962	2,164
Taxes other than income	2,995	1,610	6,068	3,122
General and administrative	5,897	5,358	11,838	9,897
Depreciation, depletion and amortization	12,010	7,010	24,358	13,612
Total expenses	**28,896**	**18,572**	**58,099**	**34,177**
Operating income	**14,807**	**7,076**	**33,620**	**15,854**
Other income (expense):				
Interest expense	(1,521)	(650)	(2,457)	(1,120)
Interest income	211	522	650	1,075
Income from continuing operations before minority interest, income taxes, discontinued operations and cumulative effect of change in accounting principle	**13,497**	**6,948**	**31,813**	**15,809**
Minority interest in Penn Virginia Resource Partners, L.P.	2,823	2,377	5,842	5,942
Income tax expense	4,312	1,629	10,486	3,555
Income from continuing operations before discontinued operations and cumulative effect of change in accounting principle	**6,362**	**2,942**	**15,485**	**6,312**
Income from discontinued operations (including gain on sale and net of taxes)	-	221	-	221
Cumulative effect of change in accounting principle	-	-	1,363	-
Net income	**$ 6,362**	**$ 3,163**	**$ 16,848**	**$ 6,533**
Income before cumulative effect of change in accounting principle, basic	$0.71	$0.33	$1.73	$0.71
Income from discontinued operations, basic	-	0.02	-	0.02
Cumulative effect of change in accounting principle, basic	-	-	0.15	-
Net Income per share, basic	**$0.71**	**$0.35**	**$1.88**	**$0.73**
Income before cumulative effect of change in accounting principle, diluted	$0.70	$0.33	$1.72	$0.70
Income from discontinued operations, diluted	-	0.02	-	0.02
Cumulative effect of change in accounting principle, diluted	-	-	0.15	-
Net income per share, diluted	**$0.70**	**$0.35**	**$1.87**	**$0.72**
Weighted average shares outstanding, basic	**8,976**	**8,927**	**8,964**	**8,918**
Weighted average shares outstanding, diluted	**9,047**	**8,984**	**9,021**	**8,968**

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

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	June 30, 2003 (unaudited)	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 11,916	$ 13,341
Accounts receivable	32,045	20,366
Current portion of long-term notes receivable	633	527
Price risk management assets	200	-
Other	1,748	1,503
Total current assets	**46,542**	**35,737**
Property and equipment		
Oil and gas properties (successful efforts method)	456,289	383,360
Other property and equipment	268,221	265,180
Less: Accumulated depreciation, depletion and amortization	(124,281)	(102,588)
Net property and equipment	**600,229**	**545,952**
Other assets	5,537	4,603
Total assets	**$ 652,308**	**$ 586,292**

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, 2003 (unaudited)	December 31, 2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 367	$ 52
Accounts payable	2,372	5,670
Accrued liabilities	23,825	16,508
Price risk management liabilities	4,907	1,621
Total current liabilities	**31,471**	**23,851**
Other liabilities	12,025	12,230
Price risk management liabilities	524	444
Deferred income taxes	67,915	62,154
Long-term debt	53,000	16,000
Long-term debt of Penn Virginia Resource Partners, L.P.	92,859	90,887
Minority interest in Penn Virginia Resource Partners, L.P.	194,370	192,770
Shareholders' equity		
Preferred stock of $100 par value- authorized 100,000 shares; none issued	-	-
Common stock of $6.25 par value 16,000,000 shares authorized; 8,984,800 and 8,946,651 shares issued at June 30, 2003 and December 31, 2002 respectively	56,154	55,915
Other paid in capital	12,694	11,436
Retained earnings	135,998	123,189
Accumulated other comprehensive income	(3,719)	(1,661)
	201,127	188,879
Less: Unearned compensation and ESOP	983	923
Total shareholders' equity	**200,144**	**187,956**
Total liabilities and shareholders' equity	**$ 652,308**	**$ 586,292**

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Cash flow from operating activities:				
Net Income	$ 6,362	$ 3,163	$ 16,848	$ 6,533
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	12,010	7,010	24,358	13,612
Minority interest	2,823	2,377	5,842	5,942
Cumulative effect of change in accounting principle	-	-	(1,363)	-
Deferred income taxes	3,498	1,523	6,135	1,880
Dry hole and unproved leasehold expense	1,080	118	1,608	159
Other	449	342	955	740
Changes in operating assets and liabilities:				
Current assets	943	(719)	(11,924)	390
Current liabilities	1,675	(3,513)	5,001	(7,318)
Other assets	6	(226)	(81)	(672)
Other liabilities	290	1,144	590	1,386
Net cash flows provided by operating activities	**29,136**	**11,219**	**47,969**	**22,652**
Cash flows from investing activities:				
Payments received on long-term notes receivable	124	109	245	335
Proceeds from sale of properties and equipment	21	1,236	66	1,300
Additions to property and equipment	(25,610)	(12,290)	(75,107)	(21,262)
Net cash flows used in investing activities	**(25,465)**	**(10,945)**	**(74,796)**	**(19,627)**
Cash flows from financing activities				
Dividends paid	(2,025)	(2,010)	(4,038)	(4,015)
Distributions paid to minority interest holders	(5,329)	(3,747)	(9,253)	(6,295)
Net proceeds from PVA borrowings	5,367	3,077	37,315	9,331
Proceeds from PVR borrowings	-	-	90,000	-
Repayments of PVR borrowings	-	-	(88,387)	-
Payments for debt issuance costs	-	-	(1,419)	-
Purchase of PVR units	-	-	-	(1,067)
Purchase of treasury stock	-	(521)	-	(557)
Issuance of stock	703	1,241	1,184	1,756
Net cash provided by (used in) financing activities	**(1,284)**	**(1,960)**	**25,402**	**(847)**
Net increase (decrease) in cash and cash equivalents	**2,387**	**(1,686)**	**(1,425)**	**2,178**
Cash and cash equivalents-beginning of period	**9,529**	**13,485**	**13,341**	**9,621**
Cash and cash equivalents-end of period	**$ 11,916**	**$ 11,799**	**$ 11,916**	**$ 11,799**
Supplemental disclosures of cash flow information:				
Cash paid during the periods for:				
Interest (net of amounts capitalized)	$ 196	$ 563	$ 970	$ 822
Income taxes	$ 5,996	$ 75	$ 6,080	$ 75

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

PENN VIRGINIA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Unaudited

June 30, 2003

1. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements include the accounts of Penn Virginia Corporation ("Penn Virginia", 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 approximately 42.5 percent of the limited partner interests. Penn Virginia Resource GP, LLC, an indirect wholly-owned subsidiary of Penn Virginia, serves as the Partnership's sole general partner. 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, 2002. Our accounting policies are consistent with those described in our Annual Report on Form 10-K for the year ended December 31, 2002, except as discussed below. Please refer to such Form 10-K for a further discussion of those policies. Operating results for the six months ended June 30, 2003 are not necessarily indicative of the results that may be expected for the year ended December 31, 2003. Certain reclassifications have been made to conform to the current period's presentation.

2. 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 APB 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 following table illustrates the effect on net income and earnings per share as if we had applied the fair value recognition provision of Statement of Financial Accounting Standard ("SFAS") No. 123, *Accounting for Stock-Based Compensation,* to stock-based employee options.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net income, as reported	$ 6,362	$ 3,163	$16,848	$ 6,533
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	169	188	224	210
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(355)	(439)	(633)	(649)
Pro forma net income	$ 6,176	$ 2,912	$16,439	$ 6,094
Earnings per share				
Basic - as reported	$0.71	$0.35	$1.88	$0.73
Basic - pro forma	$0.69	$0.33	$1.83	$0.68
Diluted - as reported	$0.70	$0.35	$1.87	$0.72
Diluted - pro forma	$0.68	$0.32	$1.82	$0.68

3. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of assets.

The fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is also added to the carrying amount of the associated asset and is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to accretion expense, which are recorded as additional depreciation, depletion and amortization. If the obligation is settled for other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

We identified all required asset retirement obligations and determined the fair value of these obligations on the date of adoption. The determination of fair value was based upon regional market and specific well or mine type information. In conjunction with the initial application of SFAS No. 143, we recorded a cumulative effect of change in accounting principle, net of taxes, of approximately $1.4 million as an increase to income. In addition, we recorded an asset retirement obligation of approximately $2.7 million. Below is a reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations as of June 30, 2003 (in thousands).

Balance, January 1, 2003	$ -
Initial adoption entry	2,685
Liabilities incurred in the current period	246
Liabilities settled in the current period	(13)
Accretion expense	75
Balance, June 30, 2003	$ 2,993

The following table summarizes the pro forma net income and earnings per share for the three and six month periods ended June 30, 2002 had the change in accounting been implemented on January 1:

	Three Months Ended June 30, 2002	Six Months Ended June 30 2002
Net Income		
As reported	$3,163	$6,533
Pro forma	$3,184	$6,575
Net income per share - reported		
Basic	$0.35	$0.73
Diluted	$0.35	$0.72
Net income per share - pro forma		
Basic	$0.35	$0.73
Diluted	$0.35	$0.73

4. HEDGING ACTIVITIES

Commodity Cash Flow Hedges

From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas and crude oil price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of costless collars and swaps. All derivative financial instruments are recognized in the financial statements at fair value in accordance with SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138.

All derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we utilize only cash flow hedges and the remaining discussion relates exclusively to this type of derivative instrument. All hedge transactions are subject to our risk management policy, which has been reviewed and approved by our Board of Directors.

We formally document all relationships between hedging instruments and hedged items, as well as the risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. We measure hedge effectiveness on a period basis. When it is determined that a derivative is not highly effective as a hedge, or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively.

Gains and losses on hedging instruments when settled are included in natural gas or crude oil production revenues in the period that the related production is delivered.

The fair values of our hedging instruments 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, 2003. The following table sets forth our positions as of June 30, 2003:

Time Period	Notional Quantities	Fixed Price or Effective Floor/Ceiling Price	Fair Value
Natural Gas	**(MMbtu per Day)**	**(Per Mmbtu)**	**(in thousands)**
Costless collars			
July 1, 2003 -September 30, 2003	5,000	\$3.37 / \$5.05	\$ (183)
July 1, 2003 - October 31, 2003	5,000	\$2.92 / \$4.42	(557)
July 1, 2003 - December 31, 2003	5,000	\$5.00 / \$7.10	95
October 1, 2003 - April 30, 2004	7,272	\$3.50 / \$5.00	(1,555)
July 1, 2003 - June 30, 2004	7,500	\$3.50 / \$5.28	(1,819)
July 1, 2003 - July 31, 2004	4,000	\$3.72 / \$6.97	(308)
July 1, 2004 - October 31, 2004	7,000	\$4.00 / \$5.24	(222)
August 1, 2004 - October 31, 2004	4,000	\$4.00 / \$5.25	(97)
May 1, 2004 - November 30, 2004	6,500	\$4.00 / \$6.87	105
Swaps			
July , 2003 - January 31, 2005	1,100 to 5,300	\$4.70	(590)
Crude Oil	**(Bbls per Day)**	**(Per Bbl)**	
Costless collars			
June 2003	500	\$23.00 / \$28.75	(27)
Swaps			
July 1, 2003 - June 30, 2004	120	\$26.58	(52)
July 1, 2003 - January 1, 2005	50 to 250	\$26.93	(20)
Total			\$ (5,230)

Based upon our assessment of our derivative contracts designated as cash flow hedges at June 30, 2003, we reported (i) an approximate price risk management liability of \$5.4 million, an approximate price risk management asset of \$0.2 million and (ii) a loss in accumulated other comprehensive income of \$3.4 million, net of a related income tax benefit of \$1.8 million. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of \$1.4 million and \$5.5 million for the three months and six months ended June 30, 2003, respectively. Based upon future oil and natural gas prices as of June 30, 2003, \$4.8 million of hedging losses are expected to be realized within the next 12 months. The amounts ultimately realized will vary due to changes in the fair value of the open derivative contracts prior to settlement. We recognized net hedging losses of $1.0 million and gains of $0.3 million for the three months and six months ended June 30, 2002, respectively.

Interest Rate Swap

In March 2003, PVR entered into an interest rate swap agreement with a notional amount of $30 million to hedge a portion of the fair value of its 5.77 percent senior unsecured notes which mature over a ten year period. This swap is designated as a fair value hedge and has been reflected as an increase of long-term debt of approximately $0.4 million as of June 30, 2003, with a corresponding increase in long-term assets. Under the terms of the interest rate swap agreement, the counterparty pays PVR a fixed annual rate of 5.77 percent on a total notional amount of $30 million, and PVR pays the counterparty a variable rate equal to the floating interest rate which will be determined semi-annually and will be based on the six month London Interbank Offering Rate ("LIBOR") plus 2.36 percent. See Note 5 (Long-term Debt) for a description of the underlying debt instrument to which the interest rate swap applies.

5. LONG-TERM DEBT

At June 30, 2003 and December 31, 2002, long-term debt consisted of the following (in thousands):

	June 30, 2003 (Unaudited)	December 31, 2002
Penn Virginia revolving credit facility	$ 53,000	$ 16,000
PVR senior unsecured notes, including fair value hedge of $359 thousand	90,359	-
PVR revolving credit facility	2,500	47,500
PVR term loan	-	43,387
	$145,859	$ 106,887

Penn Virginia Revolving Credit Facility

We have a $150 million secured revolving credit facility which expires in October 2004 (the "Revolver") with a group of major commercial banks. Effective April 24, 2003, the borrowing base was increased from $140 million to $150 million.

The Revolver is governed by a borrowing base calculation and will be redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.375 to 1.875 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the federal funds rate plus a margin ranging from 0.375 to 0.875 percent or the prime rate as announced by the agent bank. The weighted average interest rate on borrowings incurred during the year ended December 31, 2002 was approximately 3.0 percent. The Revolver provides for the issuance of letters of credit that are limited to no more than an aggregate of $10 million. The financial covenants require us to maintain a certain level of net worth, and certain ratios of debt-to-earnings and earnings-to-interest. Certain dividend limitation restrictions are also included. We are currently in compliance with all of our covenants.

PVR Revolving Credit Facilty

In connection with the closing of PVR's initial public offering in October 2001, PVR entered into a $50 million revolving credit facility (the "PVR Revolver") with a syndicate of major commercial banks, which expires in October 2004. The PVR Revolver is available for general partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $5.0 million sublimit that is available for working capital needs and distributions and a $5.0 million sublimit for the issuance of letters of credit.

Indebtedness under the PVR Revolver will bear interest, at PVR's option, at either (i) the higher of the federal funds rate plus 0.50 percent or the prime rate as announced by PNC Bank, N.A. or (ii) the Eurodollar rate plus an applicable margin which ranges from 1.25 percent to 1.75 percent based on PVR's ratio of consolidated indebtedness to consolidated EBITDA (as defined in the PVR Revolver) for the four most recently completed fiscal quarters. The PVR Revolver prohibits PVR from making distributions to unitholders and distributions in excess of available cash if any potential default or event of default, as defined in the PVR Revolver, occurs or would result from the distribution. The financial covenants of the PVR Revolver require PVR to maintain certain ratios of debt-to-earnings and earnings-to-interest. The Partnership is currently in compliance with all of the PVR Revolver covenants.

PVR Senior Unsecured Notes

In March 2003, PVR closed a private placement of $90 million of senior unsecured notes (the "PVR Notes"). The PVR Notes bear interest at a fixed rate of 5.77 percent and mature over a ten year period ending in March 2013, with semi-annual interest payments through March 2004 followed by semi-annual principal and interest payments beginning in September 2004. Proceeds of the PVR Notes after the payment of expenses related to the offering were used to repay a $43.4 million PVR term loan and to repay the majority outstanding under the PVR Revolver.

The $43.4 million PVR term loan that was repaid in March 2003 originated in conjunction with the closing of PVR's initial public offering in October 2001. PVR borrowed $43.4 million under the term loan and purchased and pledged $43.4 million of U.S. Treasury notes, which secured the credit facility. In 2002, the U.S. Treasury Notes were liquidated for the purpose of funding acquisitions.

Concurrent with the closing of the PVR Notes, PVR also entered into an interest rate derivative transaction to convert $30 million of the debt from a fixed interest rate to a floating interest rate, as described further in Note 4 (Hedging Activities, Interest Rate Swap).

The PVR Notes prohibit PVR from making distributions to unitholders and distributions in excess of available cash if any potential default or event of default, as defined in the PVR Notes, occurs or would result from the distribution. In addition, the PVR Notes contain various covenants similar to those contained in the PVR Revolver.

6. COMMITMENTS AND CONTINGENCIES

Legal

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

Advisory Services

On March 25, 2002, we entered into an agreement with an investment banking firm to provide financial advisory services in connection with our receipt and consideration of various shareholder proposals. The fees payable under this agreement are determined based upon the market capitalization and long-term debt of the Company and cannot be calculated with certainty until the time of actual payment which will occur on or before November 30, 2003. As of June 30, 2003, based on a range of probable payment amounts, we have recognized a cumulative liability of approximately $3.0 million for services rendered in connection with this agreement, of which $0.9 million and $1.6 million were recognized in general and administrative expense for the three and six months ended June 30, 2003, respectively. We will continue to accrue additional expenses under this agreement in accordance with our best estimate of the amount due for such services.

7. EARNINGS PER SHARE

The following is a reconciliation of the amounts used in the calculation of basic and diluted earnings per share for income from continuing operations and net income at June 30, 2003 and 2002 (in thousands, except share data).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Income from continuing operations	$ 6,362	$ 2,942	$ 15,485	$ 6,312
Income from discontinued operations	-	221	-	221
Cumulative effect of change in accounting principle	-	-	1,363	-
Net income	$ 6,362	$ 3,163	$ 16,848	$ 6,533
Weighted average shares, basic	8,976	8,927	8,964	8,918
Dilutive securities:				
Stock options	71	57	57	50
Weighted average shares, diluted	9,047	8,984	9,021	8,968
Income from continuing operations per share, basic	$ 0.71	$ 0.33	$ 1.73	$ 0.71
Income from discontinued operations per share, basic	-	0 02	-	0 02
Cumulative effect of change in accounting principle, basic	-	-	0.15	-
Net income per share, basic	$ 0.71	$ 0.35	$ 1.88	$ 0.73
Income from continuing operations per share, diluted	$ 0.70	$ 0.33	$ 1.72	$ 0.70
Income from discontinued operations per share, diluted	-	0.02	-	0.02
Cumulative effect of change in accounting principle, diluted	-	-	0.15	-
Net income per share, diluted	$ 0.70	$ 0.35	$ 1.87	$ 0.72

8. COMPREHENSIVE INCOME

Comprehensive income represents changes in retained earnings during the reporting period, including net income and charges directly to retained earnings, which are excluded from net income. For the three- and six-month periods ended June 30, 2003 and 2002, the components of comprehensive income are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net income	$ 6,362	$ 3,163	$ 16,848	$ 6,533
Unrealized gains (losses) on price risk management, net of tax	(2,090)	219	(5,628)	(2,702)
Reclassification adjustment for price risk management, net of tax	900	629	3,570	(193)
Comprehensive income	$ 5,172	$ 4,011	$ 14,790	$ 3,638

9. SEGMENT INFORMATION

Penn Virginia's operations are classified into two operating segments:

Oil and gas - crude oil and natural gas exploration, development and production.

Coal royalty and land management - the leasing of mineral rights and subsequent collection of royalties and the development and harvesting of timber. This segment's activities are conducted through Penn Virginia's ownership interest in Penn Virginia Resource Partners, L.P.

All other - primarily represents corporate functions.

	Oil and Gas	Coal Royalty and Land Management	All Other	Total
		(in thousands)		
For the three months ended June 30, 2003:				
Revenues	$30,208	$13,281	$ 214	$43,703
Operating costs and expenses	11,152	2,915	2,819	16,886
Depreciation, depletion and amortization	7,818	4,150	42	12,010
Operating income (loss)	11,238	6,216	(2,647)	14,807
Interest expense				(1,521)
Interest income				211
Income before minority interest and taxes				$13,497
Additions to property and equipment	$25,173	$ 177	$ 260	$25,610
For the three months ended June 30, 2002:				
Revenues	$17,616	$ 7,791	$ 241	$25,648
Operating costs and expenses	7,224	2,244	2,094	11,562
Depreciation, depletion and amortization	6,288	668	54	7,010
Operating income (loss)	4,104	4,879	(1,907)	7,076
Interest expense				(650)
Interest income				522
Income before minority interest and taxes				$ 6,948
Additions to property and equipment	$12,023	$ 267	$ -	$12,290

	Oil and Gas	Coal Royalty and Land Management	All Other	Total
	(in thousands)			
For the six months ended June 30, 2003:				
Revenues	$64,756	$26,522	$ 441	$91,719
Operating costs and expenses	22,401	5,862	5,478	33,741
Depreciation, depletion and amortization	15,921	8,368	69	24,358
Operating income (loss)	26,434	12,292	(5,106)	33,620
Interest expense				(2,457)
Interest income				650
Income before minority interest and taxes				$31,813
Additions to property and equipment	$73,324	$ 1,446	$ 337	$75,107
For the six months ended June 30, 2002:				
Revenues	$30,994	$18,546	$ 491	$50,031
Operating costs and expenses	12,263	4,837	3,465	20,565
Depreciation, depletion and amortization	11,943	1,563	106	13,612
Operating income (loss)	6,788	12,146	(3,080)	$15,854
Interest expense				(1,120)
Interest income				1,075
Income before minority interest and taxes				$15,809
Additions to property and equipment	$20,213	$ 781	$ 268	$21,262

10. NEW ACCOUNTING STANDARDS

In November 2002, the FASB issued Interpretation No. 45 (FIN 45), *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others*, which clarifies the requirements of SFAS No. 5, *Accounting for Contingencies*, relating to a guarantor's accounting for and disclosure of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also will require certain guarantees that are issued or modified after December 31, 2002, including certain third-party guarantees, to be initially recorded on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. The financial statement recognition provisions are effective prospectively. The Company has no outstanding guarantees as of June 30, 2003.

The Financial Accounting Standards Board ("FASB") and representatives of the accounting staff of the SEC are currently engaged in discussions regarding the application of certain provisions of SFAS No. 141,"Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to oil and gas companies. The FASB and the SEC staff are considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures.

Historically, we have included oil and gas lease acquisition costs as a component of oil and gas properties. In the event the FASB and SEC staff determine that costs associated with mineral rights are required to be classified as intangible assets, some portion of the Company's oil and gas property acquisition costs since the June 30, 2001 effective date of SFAS Nos. 141 and 142 would be separately classified on its balance sheets as intangible assets. However, the Company's results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with successful efforts accounting rules. Further, we do not believe the classification of oil and gas lease acquisition costs as intangible assets would have an impact on our compliance with covenants under our debt agreements.

Regarding PVR, the accounting staff of the SEC is also currently engaged in discussions regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the mining industry, including those which, like the Partnership, do not actually conduct any mining operations. The SEC staff is considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with coal mineral rights as intangible assets on the balance sheet, apart from other capitalized property costs, and provide specific footnote disclosures. Historically, PVR has included owned and leased mineral interests as a component of property and equipment on its balance sheet. It is likely that the SEC staff will determine that costs associated with leased coal mineral interests are required to be classified as intangible assets. PVR coal acquisition costs for leased mineral interests are not significant. However, the SEC is also considering what constitutes an "owned" mineral interest, and depending on the outcome of that interpretation, a substantial portion of PVR's fee mineral acquisition costs since the June 30, 2001 effective date of SFAS No. 141 and 142 could also be required to be classified as an intangible asset on its balance sheet. The Partnership's results of operations would not be affected as a result of any such reclassification, since all intangible assets would continue to be depleted on a unit of production basis. Further, the Partnership does not believe any such reclassification would have any impact on its compliance with covenants under its debt agreements.

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

We operate in two business segments: oil and gas and coal royalty and land management. The oil and gas segment includes the exploration for, and the development and production of, crude oil, condensate and natural gas primarily in the eastern and Gulf Coast onshore areas of the United States, and our ownership of mineral rights to oil and gas reserves. The coal royalty and land management segment includes the leasing of coal reserves, the providing of services to coal mining companies through fee-based assets, and the sale of timber, owned by Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR"). The assets, liabilities and earnings of PVR are included in our consolidated financial statements, with the public unitholders' 55 percent interest in PVR reflected as a minority interest. Selected operating and financial data by segment is presented below.

Critical Accounting Policies and Estimates

Oil and Gas Properties. We use the successful efforts method of accounting for our oil and gas operations. Under this method of accounting, costs to acquire mineral interests in oil and gas properties and to drill and equip development wells (including development dry holes) are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively. Costs of drilling exploratory wells are initially capitalized, and later charged to expense if it is determined that a well does not justify commercial development. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred.

The costs of unproved leaseholds are capitalized pending the results of exploration efforts. Unproved leasehold costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, that the cost of the property has been impaired. As unproved leaseholds are determined to be productive, the related costs are transferred to proved leaseholds and amortized on a unit-of-production basis.

Other Property and Equipment. Other property and equipment is carried at cost and includes expenditures for additions and improvements, which substantially increase the productive lives of existing assets. Maintenance and repair costs are expensed as incurred. Depreciation of property and equipment is generally computed using the straight-line method over the estimated useful lives of such property and equipment, varying from 3 years to 20 years. Coal properties are depleted on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. When an asset is retired or sold, its cost and related accumulated depreciation are removed from the accounts. The difference between undepreciated cost and proceeds from disposition is recorded as a gain or loss.

Impairment of Long-Lived Assets. We review our long-lived assets to be held and used, including proved oil and gas properties and the Partnership's coal properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss must be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we would recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the expected present value of future net cash flows from proved reserves, discounted utilizing a risk-free interest rate commensurate with the remaining lives for the respective oil and gas properties.

Oil and Gas Revenues. Oil and gas revenues are recognized when crude oil and natural gas volumes are produced and sold for our account. Each working interest owner in a well generally has the right to a specific percentage of production, and often actual production sold for any particular owner will differ from such owner's ownership percentage. When, under contract terms, these differences are settled in cash, revenues are adjusted accordingly.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by the Partnership’s lessees and the corresponding revenue from those sales. Approximately two-thirds of PVR's 2003 coal royalty revenues and all of the 2002 coal royalty revenues received from PVR's coal lessees were based on a minimum dollar royalty per ton and/or a percentage of the gross sales price, with minimum monthly or annual rental payments. The remainder of PVR's coal royalty revenues were derived from fixed royalty rate leases, which escalate annually, with pre-established minimum monthly payments. Coal royalty revenues are accrued on a monthly basis, based on PVR's best estimates of coal mined on its properties.

Coal Services. Coal services revenues are recognized when lessees use the Partnership's facilities for the processing and transportation of coal. Coal services revenues consist of fees collected from the Partnership's lessees for the use of the Partnership's loadout facility, coal preparation plants and dock loading facility.

Timber. Timber revenues are recognized when timber is sold in a competitive bid process involving sales of standing timber on individual parcels and, from time to time, on a contract basis where independent contractors harvest and sell the timber. Timber revenues are recognized when the timber parcel has been sold or when the timber is harvested by the independent contractors. Title and risk of loss pass to the independent contractors upon the execution of the contract. In addition, if the contractors do not harvest the timber within the specified time period, the title of the timber reverts back to the Partnership with no refund of previous amounts received by us

Minimum Rentals. Most of the Partnership's lessees are required to make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalty revenues. If a lessee fails to meet its minimum production for the recoupment period, the deferred income attributable to the minimum payment is recognized as minimum rental revenues and is included in other revenues.

Price Risk Management Activities. From time to time, we enter into derivative financial instruments to mitigate our exposure to natural gas and crude oil price volatility. The derivative financial instruments, which are placed with major financial institutions that we believe are minimum credit risks, take the form of costless collars and swaps. All derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we are utilizing only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. All hedge transactions are subject to our risk management policy, which has been reviewed and approved by our Board of Directors. We formally document all relationships between hedging instruments and hedged items, as well as the risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. We measure hedge effectiveness on a period basis. When it is determined that a derivative is not highly effective as a hedge, or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively. When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively. Gains and losses on hedging instruments when settled are included in natural gas or crude oil production revenues in the period that the related production is delivered. The fair values of our hedging instruments are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices.

Reserves. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of properties with 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. Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods.

Results of Operations - Three Months Ended June 30, 2003 Compared to Three Months Ended June 30, 2002

We reported net income of $6.4 million, or $0.70 per share (diluted), for the three months ended June 30, 2003, compared with $3.2 million, or $0.35 per share (diluted), for the three months ended June 30, 2002. Revenues increased $18.1 million, primarily as a result of increased natural gas and crude oil prices received and increased production of natural gas, crude oil and coal. Operating expenses were $10.3 million higher during the three months ended June 30, 2003 than in the 2002 comparable period, primarily due to our acquisition of certain south Texas oil and gas properties in January 2003, and PVR's acquisition of certain coal reserves from Peabody in December 2002 (the "Peabody Acquisition"). See "Acquisitions" for more information.

Variances in revenues and operating expenses are explained in more detail in the segment discussions following.

General and administrative. On a consolidated basis, general and administrative expense was $5.9 million for the three months ended June 30, 2003, compared with $5.4 million for the same period in 2002. The $0.5 million increase was due primarily to a general increase in the number of employees of the Company and an increase in insurance premiums.

Interest expense. On a consolidated basis, interest expense was $1.5 million for the three months ended June 30, 2003, compared with $0.7 million for the same period in 2002, an increase of $0.8 million or 134 percent. The increase was primarily due to increased debt levels in connection with various coal and oil and gas property acquisitions in late 2002 and early this year.

Interest income. Interest income was $0.2 million for the three months ended June 30, 2003, compared with $0.5 million for the same period in 2002. The decrease was primarily due to the liquidation of U.S. Treasury Notes during the last half of 2002.

Minority interest. Minority interest for the three months ended June 30, 2003 was $2.8 million, compared to $2.4 million for the same period in 2002. The increase was primarily due to an increase in ownership percentage by the public unitholders to approximately 55 percent for the second quarter of 2003 from 48 percent for the same period in 2002.

Income taxes. The effective tax rate for the three months ended June 30, 2003 was 40 percent, compared to 36 percent for the comparable period in 2002. The increase was primarily the result of the absence of Section 29 tax credits, for which the tax regulations expired at the end of 2002. At this time, there is no new legislation which allows similar tax benefits.

Results of Operations - Six Months Ended June 30, 2003 Compared to Six Months Ended June 30, 2002

We reported net income of $16.8 million, or $1.87 per share (diluted), for the six months ended June 30, 2003, compared with $6.5 million, or $0.72 per share (diluted), for the six months ended June 30, 2002. Revenues increased $41.7 million, primarily as a result of increased natural gas and crude oil prices received and increased production of natural gas, crude oil and coal. Operating expenses were $23.9 million higher during the six months ended June 30, 2003 than in the 2002 comparable period, primarily due to our acquisition of certain south Texas oil and gas properties in January 2003 and the Peabody Acquisition. See "Acquisitions" for more information.

Variances in revenues and operating expenses are explained in more detail in the segment discussions following.

General and administrative. On a consolidated basis, general and administrative expense was $11.8 million for the six months ended June 30, 2003, compared with $9.9 million for the same period in 2002. The $1.9 million increase was due primarily to advisory services and legal fees related to the consideration of various shareholder proposals, a general increase in the number of employees for the Company and higher insurance premiums.

Interest expense. On a consolidated basis, interest expense was $2.5 million for the six months ended June 30, 2003, compared with $1.1 million for the same period in 2002, an increase of $1.4 million or 119 percent. The increase was primarily due to increased debt levels in connection with various coal and oil and gas property acquisitions in late 2002 and early this year.

Interest income. Interest income was $0.7 million for the six months ended June 30, 2003, compared with $1.1 million for the same period in 2002. The decrease was primarily due to the liquidation of U.S. Treasury Notes during the last half of 2002.

Minority interest. Minority interest for the six months ended June 30, 2003 was $5.8 million, compared to $5.9 million for the same period in 2002. The decrease was primarily due to a decrease in PVR's net income for the respective periods, offset in part by an increase in ownership percentage by the public unitholders to approximately 55 percent for the first half of 2003 from 48 percent for the same period in 2002.

Income taxes. The effective tax rate for the six month period ended June 30, 2003 was 40 percent, compared to 36 percent for the comparable period in 2002. The increase was primarily the result of the absence of Section 29 tax credits, for which the tax regulations expired at the end of 2002. At this time, there is no new legislation which allows similar tax benefits.

Acquisitions

Oil and Gas

On January 22, 2003, we acquired a 25 percent non-operating working interest in properties located in a producing field in south Texas ("the south Texas acquisition"). Proved reserves of 31.8 billion cubic feet equivalent of natural gas were acquired in a cash transaction with a private investor group for $32.5 million, or $1.02 per thousand cubic feet equivalent. The acquisition, which was effective December 31, 2002, was financed with the Company's existing credit facility. Nine producing wells were acquired at the time of the acquisition, and comprised approximately one-third of the total proved reserves acquired. Seven wells have been drilled in the field since the acquisition date and are currently producing. Additional wells are expected to be drilled over the next two to three years to fully develop the field.

Coal Royalty and Land Management

In December 2002, PVR announced the formation of a strategic alliance with Peabody Energy Corporation, the largest private sector coal company in the world. Central to the transaction was the purchase and leaseback of approximately 120 million tons of predominately low sulfur, low BTU coal reserves located in New Mexico (80 million tons) and predominately high sulfur, high BTU coal reserves located in northern West Virginia (40 million tons). The Peabody Acquisition, which included 8,800 mineral acres, was funded with $72.5 million in cash, 1,522,325 common units and 1,240,833 class B common units. All of the class B common units were converted to regular common units, in accordance with their terms, upon the approval of PVR common unitholders on July 29, 2003. Of the units issued, 52,700 common units are currently being held in escrow pending Peabody acquiring and transferring to PVR certain of the West Virginia reserves purchased. As a result of the escrowed common units, approximately one million tons of coal reserves were excluded from reserve totals, and 52,700 common units were excluded from units issued, in the Partnership's financial statements for the period ended June 30, 2003.

In addition to the Peabody Acquisition, in August 2002, PVR purchased approximately 16 million tons of reserves located on the Upshur properties in northern Appalachia for $12.3 million (the "Upshur Acquisition"). The Upshur Acquisition was PVR's first exposure outside of central Appalachia. The properties, which include approximately 18,000 mineral acres, contain predominately high sulfur, high BTU coal reserves.

In May 2001, PVR acquired the Fork Creek property in West Virginia, purchasing approximately 53 million tons of coal reserves for $33 million. In early 2002, the operator at Fork Creek filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. Fork Creek's operations were idled on March 4, 2002. The operator continued to pay minimum royalties until PVR recovered its lease on August 31, 2002. In November 2002, PVR purchased various infrastructure at Fork Creek, including a 900-ton per hour coal preparation plant and a unit-train loading facility and a railroad-granted rebate on coal loaded through the facility for $5.1 million plus the assumption of approximately $2.4 million in reclamation liabilities and approximately $0.6 million of stream mitigation obligations. PVR re-leased this property in May 2003 and assigned all reclamation and mitigation liabilities to the new lessee, which agreed to be responsible for those liabilities.

During the three and six months ended June 30, 2003, the Peabody and Upshur Acquisitions were the primary reasons for increased coal royalty revenue and increased depreciation, depletion and amortization expense for PVR, compared with the same periods of 2002.

Oil and Gas Segment

Operating income for the oil and gas segment was $11.2 million for the three months ended June 30, 2003, compared with $4.1 million for the comparable period of 2002. Operational and financial data for the Company's oil and gas segment for the three months ended June 30, 2003 and 2002 is summarized as follows:

Operations and Financial Summary

	Three Months Ended June 30,			
Production	2003		2002	
Natural gas (MMcf)	4,860		4,643 **	
Oil and condensate (MBbls)	161		76 **	
Total equivalent production (MMcfe)	5,826		5,099	
	(in thousands, except per unit amount)			
Revenues:				
Natural gas * (including $/Mcf)	$ 25,904	$ 5.33	$ 15,683	$ 3.38
Oil and condensate * (including $/Bbl)	4,314	26.80	1,875	24.67
Other income	(10)		58	
Total revenues (including $/Mcfe)	30,208	5.19	17,616	3.45
Expenses (including $/Mcfe):				
Lease operating	3,294	0.57	1,974	0.39
Exploration	3,656	0.63	2,005	0.39
Taxes other than income	2,478	0.43	1,315	0.26
General and administrative	1,724	0.30	1,930	0.38
Depreciation, depletion and amortization	7,818	1.34	6,288	1.23
Total expenses	18,970	3.27	13,512	2.65
Operating Income (including $/Mcfe)	$ 11,238	$ 1.92	$ 4,104	$ 0.80

*Includes the effect of hedging activities in the respective periods.
**Excludes 18 MMcf natural gas and 16 MBbls oil and condensate production related to discontinued operations.

For the three months ended June 30, 2003, approximately 54 percent of our natural gas and 38 percent of our crude oil production was hedged at an average floor price of $3.72 per MMbtu and ceiling price of $5.48 per MMbtu for natural gas, and an average floor price of $24.00 per barrel and ceiling price of $28.29 per barrel for crude oil. The effects of these hedges were to decrease the average natural gas prices received by $0.28 per Mcf and the average crude oil prices received by $0.29 per barrel.

See Note 4 (Hedging Activities) in the Notes to the Consolidated Financial Statements for details of costless collars and fixed price swaps. We will continue to hedge the price received for market-sensitive production through the use of fixed price term contracts or derivatives when, in management's opinion, circumstances warrant.

Natural gas. Natural gas sales increased by $10.2 million, or 65 percent, for the three months ended June 30, 2003, compared with the same period of 2002. The average natural gas price received was 58 percent higher in the second quarter of 2003, compared with the same quarter of the prior year. In addition, production increased 217 MMcf, or five percent, in the second quarter of 2003 compared with the same period in 2002. The production increase was primarily related to the south Texas acquisition and the drilling program in 2002 and the first half of this year.

Oil and condensate. Oil sales increased by $2.4 million for three months ended June 30, 2003, compared with the same period of 2002. The increase was primarily due to increased production of 85MBbls or 112 percent related to the south Texas acquisition in January 2003. Average realized prices received for crude oil production also increased by $2.13 per barrel, or nine percent.

Lease operating expenses. Operating expenses for the three months ended June 30, 2003 were $3.3 million, compared with $2.0 million in the comparable period of 2002. The $1.3 million increase relates to the operations associated with the recently acquired south Texas properties and new producing wells resulting from the successful drilling activities over the last twelve months. In addition to new operations, there was approximately $0.8 million of the increase associated with maintenance and workover costs in various fields.

Exploration expenses. Exploration expenses for the three months ended June 30, 2003 increased to $3.7 million, compared with $2.0 million in the comparable period of 2002. The increase was primarily due to the acquisition of seismic data to evaluate both existing and new prospects. Additionally, approximately $1.0 million related to unsuccessful wells was expensed in the second quarter of 2003.

Taxes other than income. Taxes other than income increased to $2.5 million for three months ended June 30, 2003 from $1.3 million in the second quarter of 2002. The increase was primarily due to higher prices received for natural gas and crude oil, as well as increased production in the second quarter of 2003 as compared to the same period in 2002.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the three months ended June 30, 2003 increased to $7.8 million, compared with $6.3 million in the comparable period of 2002. The increase was primarily due to higher production associated with the recently acquired south Texas properties and the successful horizontal drilling of coalbed methane properties.

Operating income for the oil and gas segment was $26.4 million for the six months ended June 30, 2003, compared with $6.8 million for the comparable period of 2002. Operational and financial data for the Company's oil and gas segment for the six months ended June 30, 2003 and 2002 is summarized as follows:

Operations and Financial Summary

	Six Months Ended June 30,			
Production	2003		2002	
Natural gas (MMcf)	9,788		8,908 **	
Oil and condensate (MBbls)	310		168 **	
Total equivalent production (MMcfe)	11,648		9,916	
	(in thousands, except per unit amount)			
Revenues:				
Natural gas * (including $/Mcf)	$55,904	$ 5.71	$27,020	$ 3.03
Oil and condensate * (including $/Bbl)	8,627	27.83	3,869	23.03
Other income	225		105	-
Total revenues (including $/Mcfe)	64,756	5.56	30,994	3.13
Expenses (including $/Mcfe):				
Lease operating	5,899	0.51	3,763	0.38
Exploration	7,901	0.68	2,049	0.21
Taxes other than income	5,082	0.44	2,567	0.26
General and administrative	3,519	0.30	3,884	0.39
Depreciation, depletion and amortization	15,921	1.37	11,943	1.20
Total expenses	38,322	3.30	24,206	2.44
Operating Income (including $/Mcfe)	$26,434	$ 2.26	$ 6,788	$ 0.69

*Includes the effect of hedging activities in the respective periods.
**Excludes 18 MMcf natural gas and 16 MBbls oil and condensate production related to discontinued operations.

For the six months ended June 30, 2003, approximately 43 percent of our natural gas and 39 percent of our crude oil production was hedged at an average floor price of $3.54 per MMbtu and ceiling price of $5.22 per MMbtu for natural gas, and an average floor price of $23.95 per barrel and ceiling price of $28.31 per barrel for crude oil. The effects of these hedges were to decrease the average natural gas prices received by $0.52 per Mcf and the average crude oil prices received by $1.21 per barrel.

See Note 4 (Hedging Activities) in the Notes to the Consolidated Financial Statements for details of costless collars and fixed price swaps. We will continue to hedge the price received for market-sensitive production through the use of fixed price term contracts or derivatives when, in management's opinion, circumstances warrant.

Natural gas. Natural gas sales increased by $28.9 million, or 107 percent, for the six months ended June 30, 2003, compared with the same period of 2002. The average natural gas price received was 88 percent higher in the first half of 2003, compared with the same period in 2002. In addition, production increased 880 MMcf, or ten percent, in the first half of 2003 compared with the same period in 2002. The production increase primarily related to the south Texas acquisition and the drilling program in 2002 and the first half of this year.

Oil and condensate. Oil sales increased by $4.8 million for the six months ended June 30, 2003, compared with the same period of 2002. The increase was primarily due to increased production of 142MBbls or 85 percent related to the south Texas acquisition in January 2003. Average realized prices received for crude oil production also increased by $4.80 per barrel, or 21 percent.

Lease operating expenses. Operating expenses for the six months ended June 30, 2003, were $5.9 million, compared with $3.8 million in the comparable period of 2002. The $2.1 million increase relates to the operations associated with the recently acquired south Texas properties and new producing wells resulting from the successful drilling activities over the last twelve months. In addition to new operations, there was approximately $1.2 million of the increase associated with maintenance and workover costs in various fields.

Exploration expenses. Exploration expenses for the six months ended June 30, 2003 increased to $7.9 million, compared with $2.0 million in the comparable period of 2002. The increase was primarily due to the acquisition of seismic data to evaluate both existing and new prospects. Approximately $1.6 million related to unsuccessful wells was expensed in the first half of 2003.

Taxes other than income. Taxes other than income increased to $5.1 million for the six months ended June 30, 2003 from $2.6 million in the first half of 2002. The increase was primarily due to higher prices received for natural gas and crude oil, as well as increased production in the first half of 2003 as compared to the same period in 2002.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the six months ended June 30, 2003 increased to $15.9 million, compared with $11.9 million in the comparable period of 2002. The increase was primarily due to higher production associated with the recently acquired south Texas properties and the successful horizontal drilling of coalbed methane properties.

Coal Royalty and Land Management Segment

The following table sets forth PVR's revenues, operating expenses and operating statistics for the three months ended June 30, 2003 compared with the same period in 2002.

	Three Months Ended June 30,		Percentage
Financial Highlights:	**2003**	**2002**	**Change**
	(in thousands, except prices)		
Revenues:			
Coal royalties	$12,247	$ 6,693	83%
Coal services	546	466	17%
Timber	193	499	(61%)
Minimum rentals	210	30	600%
Other	85	103	(17%)
Total revenues	13,281	7,791	70%
Operating costs and expenses:			
Operating	895	446	101%
Taxes other than income	293	261	12%
General and administrative	1,727	1,537	12%
Depreciation, depletion and amortization	4,150	668	521%
Total operating costs and expenses	7,065	2,912	143%
Operating income	$ 6,216	$ 4,879	27%

Coal royalties. Coal royalty revenues for the three months ended June 30, 2003 were $12.2 million compared to $6.7 million for the same period in 2002, an increase of $5.5 million, or 83 percent, while production by PVR lessees increased 3.5 million tons, or 113 percent. The Peabody and Upshur Acquisitions in the last half of 2002 accounted for 3.0 million tons of the variance and the remainder was primarily attributable to stronger market conditions. The increase in production was partially offset by a decrease in the average royalty per ton of $0.30, or 14 percent, over the same periods, which was primarily attributable to the lower fixed royalty rates per ton received under the Peabody leases.

Coal services. Coal services revenues increased $0.1 million, or 17 percent, to $0.5 million in the second quarter of 2003. The increase was attributable to the addition of two small preparation plants which PVR made available to two of its lessees.

Timber sales. Timber revenues decreased to $0.2 milllion for the three months ended June 30, 2003, compared with $0.5 million in the second quarter of 2002, a decrease of $0.3 million, or 61 percent. Volume sold declined 1,624 thousand board feet (Mbf), or 61 percent, to 1,052 Mbf in the second quarter of 2003, compared with 2,676 Mbf for the same period in 2002. The decrease in volume sold was due to the timing of parcel sales.

Minimum rentals. Minimum rental revenues increased to $0.2 million for the three months ended June 30, 2003 from $30 thousand in the comparable period of 2002. The increase was primarily due to the timing of expiring recoupments from two of PVR's lessees in the second quarter of 2002.

Other income. Other income remained constant at $0.1 million for the three months ended June 30, 2003 and 2002. Other income primarily consists of land rental and wheelage income, which are fees received by us for transportation across our surface property.

Operating expenses. Operating expenses increased by 101 percent to $0.9 million in the second quarter of 2003, compared with $0.4 million in the same period of 2002. The increase was due to costs to maintain an idle mine on PVR's Fork Creek property and an increase in production on PVR subleased properties. PVR leased the Fork Creek property in May 2003, and the on-going maintenance costs were assumed by the new lessee as of that date.

Taxes other than income. Taxes other than income remained relatively constant at $0.3 million for the three months ended June 30, 2003 and 2002.

General and administrative. General and administrative expenses increased $0.2 million, or 12 percent, to $1.7 million in the second quarter of 2003, from $1.5 million in the same period of 2002. The increase was primarily attributable to an increase in insurance premiums and additional recurring expenses associated with the Peabody Acquisition.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the three months ended June 30, 2003 was $4.2 million compared with $0.7 million for the same period of 2002, an increase of 521 percent. This increase was a result of higher depletion rates caused by higher cost bases relative to reserves added as well as increased production, both of which related primarily to the Peabody and Upshur Acquisitions completed during the last half of 2002.

The following table sets forth PVR's revenues, operating expenses and operating statistics for the six months ended June 30, 2003 compared with the same period in 2002.

Financial Highlights:	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002	Percentage Change
	(in thousands, except prices)		
Revenues:			
Coal royalties	$23,698	$15,184	56%
Coal services	1,039	877	18%
Timber	749	1,081	(31%)
Minimum rentals	815	900	(9%)
Other	221	504	(56%)
Total revenues	26,522	18,546	43%
Operating costs and expenses:			
Operating	1,735	1,331	30%
Taxes other than income	589	422	40%
General and administrative	3,538	3,084	15%
Depreciation, depletion and amortization	8,368	1,563	435%
Total operating costs and expenses	14,230	6,400	122%
Operating income	$12,292	$12,146	1%

Coal royalties. Coal royalty revenues for the six months ended June 30, 2003 were $23.7 million compared to $15.2 million for the same period in 2002, an increase of $8.5 million, or 56 percent, while production by PVR lessees increased 6.1 million tons, or 89 percent, which was a direct result of the Peabody and Upshur Acquisitions in the last half of 2002. The increase in production was partially offset by a decrease in the average royalty per ton of $0.38, or 17 percent, over the same periods, which was primarily attributable to the lower fixed royalty rates per ton received from Peabody leases.

Coal services. Coal services revenues increased $0.1 million, or 18 percent, to $1.0 million in the six months ended June 30, 2003, compared with $0.9 million in the same period of 2002. The increase was attributable to the addition of two small preparation plants which PVR made available to two of its lessees.

Timber sales. Timber revenues decreased to $0.7 million for the six months ended June 30, 2003, compared with $1.1 million in the comparable period of 2002, a decrease of $0.4 million, or 31%. Volume sold declined 1,921 thousand board feet (Mbf), or 33 percent, to 3,881Mbf in the first half of 2003, compared with 5,802 Mbf for the same period in 2002.

Minimum rentals. Minimum rental revenues decreased to $0.8 million for the six months ended June 30, 2003 from $0.9 million in the comparable period of 2002. The decrease was primarily due to the timing of expiring recoupments from two of PVR's lessees in the first half of 2002.

Other income. Other income decreased to $0.2 million for the six months ended June 30, 2003, compared with $0.5 million for the same period in 2002. The $0.3 million decrease was primarily due to the expiration of a railroad rebate received for the use of a specific portion of railroad by one of PVR's lessees, which was paid in full in the fourth quarter of 2002.

Operating expenses. Operating expenses increased by 30 percent, to $1.7 million for the six months ended June 30, 2003, compared with $1.3 million in the same period of 2002. The increase was due to costs to maintain an idle mine on PVR's Fork Creek property. PVR leased the Fork Creek property in May 2003, and the on-going maintenance costs were assumed by the new lessee as of that date.

Taxes other than income. Taxes other than income increased by 40 percent, to $0.6 million for the six months ended June 30, 2003, compared with $0.4 million in the same period of 2002. The variance was attributable to increased property taxes as a result of assuming the property tax obligation on the Fork Creek property upon re-acquiring the lease from the bankrupt lessee and an increase in West Virginia franchise taxes relating to the Peabody and Upshur Acquisitions. PVR leased the Fork Creek property in May 2003, and the on-going property taxes were assumed by the new lessee as of that date.

General and administrative. General and administrative expenses increased $0.4 million, or 15 percent, to $3.5 million in the first half of 2003, from $3.1 million in the same period of 2002. The increase was primarily attributable to an increase in insurance premiums and additional recurring expenses associated with the Peabody Acquisition.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the six months ended June 30, 2003 was $8.4 million compared with $1.6 million for the same period of 2002, an increase of 435 percent. This increase was a result of higher depletion rates caused by higher cost bases relative to reserves added as well as increased production, both of which related primarily to the Peabody and Upshur Acquisitions completed during the last half of 2002.

Liquidity and Capital Resources

The Company and PVR operate with independent capital structures, and the Company receives cash from PVR in the form of quarterly cash distributions for the subordinated and common limited partner units it owns, currently comprising approximately 42.5 percent of PVR's ownership, and for its general partnership interest in PVR, currently two percent. The Company and PVR have separate credit facilities, and neither entity guarantees the debt of the other. Since PVR's public offering in October 2001, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and, in the case of PVR's Peabody Acquisition, issuance of new partnership units. We expect that the individual cash needs of the Company and PVR will continue to be met separately with a combination of these funding sources.

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

Cash Flows from Operating Activities

Net cash provided by operating activities was $48.0 million for the six months ended June 30, 2003, compared with $22.7 million for the same period in 2002. The increase was mostly due to higher realized natural gas and crude oil prices and increased production, offset in part by higher exploration and operating expenses.

Natural gas production and, to a lesser extent, crude oil production, along with the prices for these commodities, are the primary factors determining changes in cash flows from operating activities for this segment. Second quarter 2003 oil and gas production was 5.8 billion cubic feet equivalent (Bcfe), 14 percent higher than the 5.1 Bcfe produced in the second quarter of 2002. Production for the first half of 2003 was 11.6 Bcfe, or 17 percent higher than the same period of 2002, due primarily to our acquisition of a 25 percent working interest in the southwest Kingsville field in south Texas. Production in the second half of 2003 is expected to increase to between 12.4 and 14.4 Bcfe as exploration successes and additional development wells commence production, as further described in "Cash Flows from Investing Activities" below.

Cash Flows from Investing Activities

For the six months ended June 30, 2003, we used $74.8 million in investing activities, compared with $19.6 million for the same period of 2002. Cash was used during these periods primarily for capital expenditures for oil and gas development and exploration activities and acquisition of oil and gas properties. Capital expenditures totaled $80.5 million for the six months ended June 30, 2003, compared with $23.7 million in the same period in 2002. The following table sets forth capital expenditures made during the periods indicated.

	Six Months Ended June 30, 2003	2002
	(in thousands)	
Oil and gas		
Development drilling	$26,226	$17,073
Exploratory drilling	4,115	463
Lease acquisitions	39,924	2,021
Field projects	2,121	1,120
Seismic and other	6,293	1,937
Oil and gas capital expenditures	78,679	22,614
Coal royalty and land management (PVR)		
Lease acquisitions	1,260	80
Support equipment and facilities	186	701
Coal royalty and land management capital expenditures	1,446	781
Other	337	268
Total capital expenditures	$80,462	$23,663

We drilled a total of 84 gross (63.3 net) wells for the six months ended June 30, 2003, compared to 63 gross (48.6 net) wells in the same period in 2002. During the second half of 2003, current plans call for the drilling of approximately 80 to 95 gross wells, approximately 70 to 85 of which are expected to be development wells. Total capital expenditures for the oil and gas segment are expected to be $40 to $58 million during the second half of 2003, and coal royalty and land management segment capital expenditures are expected to be $1.0 to $1.5 million for the same period, primarily for the construction of a coal preparation plant on the Partnership's Coal River property.

Western Region Operations (Onshore Gulf Coast and West Texas)

We drilled five wells in our Western region during the second quarter of 2003, including three development wells that are on production and two exploration wells, one of which was unsuccessful. Including these wells, we had ten successes in 11 attempts in the first six months of 2003. The three second quarter development wells were drilled in the Vicksburg objective in our Southwest Kingsville Field in Kleburg County, Texas, in which we acquired a 25 percent non-operated working interest earlier this year. Current plans for Southwest Kingsville include the drilling of five to seven more development wells during the second half of 2003. Additionally, a Queen City objective exploration well drilled in the our Tom Lyne field in South Texas' Live Oak County was unsuccessful, with a dry hole cost of $0.3 million net to the Company. Plans call for three or four more gross exploration wells to be drilled in south Texas in the second half 2003. Included in this plan is a well to test the Frio interval in our Fannett Field in Jefferson County, a salt dome on which we recently acquired a 3-D seismic survey, and a well to test the Yegua interval on our Richard King prospect in Nueces County, which is one of our higher risk prospects and carries an associated $10.4 million of unproved leasehold costs. If successful, the well has potential for significant reserve additions.

In south Louisiana, we participated in the drilling of one successful exploration well during the second quarter. The S.L. 17265 #1 well in the Stella Field, located in Plaquemines Parish, was completed in the Cris I sands and had a final test rate of 9.1 million cubic feet per day (MMcfpd) of natural gas and 201 barrels of oil per day (Bopd) with a flowing tubing pressure of 3,863 pounds per square inch (psi). We have an approximate 20 percent non-operated working interest in the well before payout, decreasing to approximately 15 percent after payout. The S.L. 17265 #1, along with two other wells completed in the first quarter of this year, are awaiting the completion of production facilities. We expect production from the three wells to commence late in the third quarter or early in the fourth quarter of 2003. Three or four more gross exploration wells are expected to be drilled in south Louisiana during the second half of the 2003.

Eastern Region Operations (Appalachia and Mississippi)

We drilled 53 gross wells in our Eastern region during the second quarter of 2003, of which 48 were development wells with an average working interest of 73.1 percent and five were exploration wells with a 100 percent working interest. All of the wells drilled in the second quarter were successful, and we will be the production operator for 39 of the wells. For the first half of 2003, we drilled 73 wells in the Eastern region with a 99 percent success rate. As discussed below, Eastern region plans for the second half of 2003 call for approximately 70 to 85 more gross development wells to be drilled in Appalachia and Mississippi, along with two relatively low risk Miocene objective exploratory wells in Louisiana and Mississippi and one exploratory coalbed methane well in the Cherokee Basin in Kansas.

We drilled 17 gross successful Selma Chalk development wells in Mississippi during the second quarter of 2003, all of which we operate and have an average working interest of 99 percent. We completed 29 gross Selma Chalk development wells in the first half of 2003. For the second half of 2003, 45 to 50 gross development wells are planned in Mississippi, including 25 to 30 wells in our Baxterville field.

We drilled 27 gross conventional multi-pay development wells in West Virginia and Virginia during the second quarter of 2003, with an average working interest of 61 percent, and 15 of which we operate. We plan to drill 15 to 20 more gross conventional well in West Virginia and Virginia during the second half of the year.

We also drilled four horizontal coalbed methane (CBM) wells in West Virginia during the second quarter. Two of the wells were drilled on our Twin Branch property in Wyoming County, where our horizontal CBM development activities began in 2001. The other two wells were drilled in the Loup Creek property, also in Wyoming County, to the north of Twin Branch. We have an average working interest of 44 percent in these four wells, and we will assume production operations on most of the wells outside of the Twin Branch area once completed. Depending on rig availability, 10 to 15 additional horizontal coalbed methane wells are expected to be drilled in West Virginia during the second half of 2003.

The five exploration wells drilled during the second quarter of 2003 were coalbed methane wells located in the Cherokee Basin in Kansas, in which we own 100 percent of the working interest and are the operator. Coal was present in all five of the wells, indicating the presence of coalbed methane gas. Commercial success will depend upon production rates after completion operations scheduled for the third quarter of 2003 are concluded. We have acquired approximately 45,000 acres in the Cherokee Basin and expect to drill one additional exploratory well there during the second half of 2003.

Cash Flows from Financing Activities

Net cash provided by financing activities totaled $25.4 million for the six months ended June 30, 2003, compared to net cash used in financing activities of $0.8 million for the same period in 2002. Credit facility borrowings provided approximately $38.9 million of cash from financing activities during the first half of 2003, offset in part by $4.0 million of dividend payments and distributions of $9.3 million to PVR's minority unitholders.

Penn Virginia has a $150 million secured revolving credit facility (the "Revolver") with a final maturity of October 2004, and we had borrowed $53.0 million against it as of June 30, 2003. As part of our semi-annual borrowing base re-determination completed in April 2003, the Revolver's borrowing base was increased from $140 million to $150 million. Under the Revolver, we have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.375 to 1.875 percent, based on the percentage of the borrowing base outstanding or (ii) the greater of the federal funds rate plus a margin ranging from 0.375 to 0.875 percent or the prime rate as announced by the agent bank. The financial covenants of the Revolver include, but are not limited to, maintaining: (i) a ratio of not more than 3.0:1.0 of total debt to EBITDAX (as defined by the Revolver), (ii) a ratio of not less than 2.5:1.0 of EBITDAX to interest expense and (iii) a minimum amount of tangible net worth (as defined by the Revolver). We are currently in compliance with all of the covenants in the Revolver. We also currently have a $5.0 million line of credit, which had $0.4 borrowed against it as of June 30, 2003. The line of credit renews annually.

PVR has a credit facility with a final maturity in October 2004 consisting of a $50.0 million unsecured revolving credit facility (the "PVR Revolver"). As of June 30, 2003, PVR had borrowed $2.5 million against the PVR Revolver. The PVR Revolver is available for general partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $5.0 million sublimit that is available for working capital needs and distributions and a $5.0 million sublimit for the issuance of letters of credit. Under the PVR Revolver, PVR has the option to elect interest at either (i) the higher of the federal funds rate plus 0.50 percent or the prime rate as announced by the agent bank or (ii) the Eurodollar rate plus an applicable margin which ranges from 1.25 percent to 1.75 percent based on PVR's ratio of consolidated indebtedness to consolidated EBITDA (as defined in the PVR Revolver) for the four most recently completed fiscal quarters. PVR is required to reduce all working capital borrowings under the working capital sublimit of the PVR Revolver to zero for a period of at least 15 consecutive days once each calendar year. The PVR Revolver prohibits PVR from making distributions to unitholders and distributions in excess of available cash if any potential default or event of default, as defined in the PVR Revolver, occurs or would result from the distribution. The financial covenants of the PVR Revolver include, but are not limited to, maintaining: (i) a ratio of not more than 2.5:1.0 of total debt to consolidated EBITDA (as defined by the PVR Revolver) and (ii) a ratio of not less than 4.00:1.00 of consolidated EBITDA to interest. The Partnership is currently in compliance with all of the PVR Revolver covenants. Based primarily on the total debt to consolidated EBITDA covenant and subsequent to PVR's issuance of senior unsecured notes as described below, available borrowing capacity under the PVR Revolver as of June 30, 2003 was approximately $16 million.

In March 2003, a $43.4 million unsecured term loan (the "PVR Term Loan), which was part of PVR's credit facility, was repaid and retired and is not available for future borrowings by PVR. Part of the proceeds from the issuance of senior unsecured notes by PVR, as described below, was used to repay the PVR Term Loan.

Also in March 2003, PVR closed a private placement of $90 million of senior unsecured notes (the "PVR Notes"). The PVR Notes bear interest at a fixed rate of 5.77 percent and mature over a ten year period ending in March 2013, with semi-annual interest payments through March 2004 followed by semi-annual principal and interest payments beginning in September 2004. Proceeds of the PVR Notes after the payment of expenses related to the offering were used to repay the $43.4 million PVR Term Loan and to repay the majority of the debt outstanding on the PVR Revolver. The PVR Notes prohibit PVR from making distributions to unitholders and distributions in excess of available cash if any potential default or event of default, as defined in the PVR Notes, occurs or would result from the distribution. In addition, the PVR Notes contain various covenants that are the same as those included in the PVR Revolver, with the exception of the financial coverage covenants, which for the PVR Notes require PVR to maintain ratios of (i) not more than 3.0:1.0 of total debt to consolidated EBITDA (as defined in the PVR Notes) and (ii) not less than 3.5:1.0 of consolidated EBITDA to interest. PVR believes it is currently in compliance with all of the covenants of the PVR Notes.

Concurrent with the closing of the PVR Notes, PVR also entered into an interest rate derivative transaction to convert $30 million of notional debt from a fixed interest rate to a floating interest rate, as described further in the "Interest Rate Risk" section of "Quantitative and Qualitative Disclosures about Market Risk" following.

Management believes its sources of funding are sufficient to meet short and long-term liquidity needs not funded by cash flows from operations. Our primary sources of funding for the remainder of 2003 are expected to be cash flows from operations supplemented as needed by borrowings under our Revolver. Excluding acquisitions, PVR's primary funding sources are also expected to be cash flows from operations supplemented as needed by borrowings under the PVR Revolver.

Legal and Environmental

Further Legal Challenges To Mountaintop Removal Mining Remain A Possibility. Over the course of the last several years, opponents of a form of surface mining called mountaintop removal have filed two lawsuits challenging the legality of that practice under federal and state laws applicable to surface mining activities. While these challenges were successful at the District Court level, the United States Court of Appeals for the Fourth Circuit overturned both of those decisions in Bragg v. Robertson in 2001 and in Kentuckians For The Commonwealth v. Rivenburgh in 2003. There can be no assurances that there will not be additional legal challenges to mountaintop removal mining. In addition, although PVR's lessees are not substantially engaged in mountaintop removal mining, it is possible that a ruling issued in response to any such challenge could have a broader impact on other forms of surface mining and deep mining, including those types of mining undertaken by PVR's lessees.

Recent Accounting Pronouncements

In November 2002, the FASB issued Interpretation No. 45 (FIN 45), *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others*, which clarifies the requirements of SFAS No. 5, *Accounting for Contingencies*, relating to a guarantor's accounting for and disclosure of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also will require certain guarantees that are issued or modified after December 31, 2002, including certain third-party guarantees, to be initially recorded on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. The financial statement recognition provisions are effective prospectively. The Company has no outstanding guarantees as of June 30, 2003.

The Financial Accounting Standards Board ("FASB") and representatives of the accounting staff of the Securities and Exchange Commission ("SEC") are currently engaged in discussions regarding the application of certain provisions of SFAS No. 141,"Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to oil and gas companies. The FASB and the SEC staff are considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures.

Historically, we have included oil and gas lease acquisition costs as a component of oil and gas properties. In the event the FASB and SEC staff determine that costs associated with mineral rights are required to be classified as intangible assets, some portion of the Company's oil and gas property acquisition costs since the June 30, 2001 effective date of SFAS Nos. 141 and 142 would be separately classified on its balance sheets as intangible assets. However, the Company's results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with successful efforts accounting rules. Further, we do not believe the classification of oil and gas lease acquisition costs as intangible assets would have an impact on our compliance with covenants under our debt agreements.

Regarding PVR, the accounting staff of the SEC is also currently engaged in discussions regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the mining industry, including those which, like the Partnership, do not actually conduct any mining operations. The SEC staff is considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with coal mineral rights as intangible assets on the balance sheet, apart from other capitalized property costs, and provide specific footnote disclosures. Historically, PVR has included owned and leased mineral interests as a component of property and equipment on its balance sheet. It is likely that the SEC staff will determine that costs associated with leased coal mineral interests are required to be classified as intangible assets. PVR coal acquisition costs for leased mineral interests are not significant. However, the SEC is also considering what constitutes an "owned" mineral interest, and depending on the outcome of that interpretation, a substantial portion of PVR's fee mineral acquisition costs since the June 30, 2001 effective date of SFAS No. 141 and 142 could also be required to be classified as an intangible asset on its balance sheet. The Partnership's results of operations would not be affected as a result of any such reclassification, since all intangible assets would continue to be depleted on a unit of production basis. Further, the Partnership does not believe any such reclassification would have any impact on its compliance with covenants under its debt agreements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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 contracts and/or financial instruments are designated as cash flow hedges and accounted for in accordance with SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138. See Note 4 (Hedging Activities) of the Notes to the Consolidated Financial Statements for more information. 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. As of July 24, 2003, our open commodity price risk management positions on average daily volumes were as follows:

Natural gas hedging positions	Costless Collars			Swaps	
	MMBtu	Price / MMBtu (a)		MMBtu	Price
	Per Day	Floor	Ceiling	Per Day	/MMBtu
Third Quarter 2003	26,500	$ 3.70	$ 5.69	2,570	$ 4.70
Fourth Quarter 2003	24,500	$ 3.80	$ 5.80	2,034	$ 4.70
First Quarter 2004	19,500	$ 3.54	$ 5.51	1,800	$ 4.70
Second Quarter 2004	18,495	$ 3.66	$ 5.98	1,533	$ 4.70
Third Quarter 2004	17,500	$ 3.98	$ 5.98	1,367	$ 4.70
Fourth Quarter 2004	13,522	$ 4.00	$ 6.40	1,234	$ 4.70
First Quarter 2005 (January)	11,000	$ 4.00	$ 6.82	1,100	$ 4.70

(a) The costless collar natural gas prices per MMBtu per quarter include the effects of basis differentials, if any, that may be hedged.

Crude oil hedging positions	Costless Collars			Swaps	
	Barrels	Price / Barrel		Barrels	Price
	Per Day	Floor	Ceiling	Per Day	/Barrel
Third Quarter 2003	-	$ -	$ -	250	$ 26.76
Fourth Quarter 2003	-	$ -	$ -	220	$ 26.74
First Quarter 2004	-	$ -	$ -	207	$ 26.73
Second Quarter 2004	-	$ -	$ -	193	$ 26.71
Third Quarter 2004	-	$ -	$ -	63	$ 26.93
Fourth Quarter 2004	-	$ -	$ -	57	$ 26.93
First Quarter 2005 (January)	-	$ -	$ -	50	$ 26.93

At June 30, 2003, we had open natural gas derivative positions with a fair value of $(5.1) million. A 10 percent increase in natural gas prices would decrease the fair value by approximately $3.1 million to a fair value of $(8.2) million. A 10 percent decrease in prices would increase the fair value by approximately $2.4 million to fair value of $(2.7) million. We also had open oil price swap positions with a fair value of $(0.1) million. A 10 percent increase in oil prices would decrease the fair value by approximately $(0.2) million to a fair value of $(0.3) million. A 10 percent decrease in oil prices would increase the fair value by approximately $0.2 million to a fair value of $0.1 million. Notional volumes and respective June 30, 2003 fair values associated with the derivative contracts are shown in Note 4 (Hedging Activities) to the consolidated financial statements.

Interest Rate Risk. At June 30, 2003, we had $53.0 million of long-term debt borrowed against the PVA Revolver. The PVA Revolver matures in October 2004 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 1.375 to 1.875 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 0.375 to 0.875 percent. As a result, our 2003 interest costs will fluctuate based on short-term interest rates relating to the PVA Revolver.

Additionally, PVR refinanced $90.0 million of credit facility borrowings with ten year, senior unsecured notes payable which have a 5.77 percent fixed interest rate throughout their term. However, PVR executed an interest rate swap transaction for $30.0 million of the amount refinanced to hedge the fair value of its senior unsecured notes. The interest rate swap is accounted for as a fair value hedge. PVR executed the transaction in a method that achieved hedge accounting in compliance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 137 and SFAS No. 138. The debt PVR incurs in the future under its credit facility will bear variable interest at either the applicable base rate or a rate based on LIBOR.

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. In addition, we and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

Such forward-looking statements may include, among other things, statements regarding development activities, capital expenditures, acquisitions and dispositions, drilling and exploration programs, expected commencement dates and projected quantities of oil, gas, or coal production, as well as projected demand or supply for coal, crude oil and natural gas, all of which may affect sales levels, prices and royalties realized by Penn Virginia and PVR.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting Penn Virginia and PVR and, therefore, involve a number of risks and uncertainties. Penn Virginia cautions that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Important factors that could cause the actual results of operations or financial condition of Penn Virginia to differ materially from those expressed or implied in the forward-looking statements include, but are not necessarily limited to: the cost of finding and successfully developing oil and gas reserves; the cost to PVR of finding new coal reserves; the ability of Penn Virginia to acquire new oil and gas reserves and of PVR to acquire new coal reserves on satisfactory terms; the price for which such reserves can be sold; the volatility of commodity prices for oil and gas and coal; the risks associated with having or not having price risk management programs; 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; the ability of lessees to obtain favorable contracts for coal produced from PVR's reserves; Penn Virginia's ability to obtain adequate pipeline transportation capacity for its oil and gas production; competition among producers in the oil and gas and coal industries generally; the extent to which the amount and quality of actual production differs from estimated recoverable proved oil and gas reserves and coal reserves; unanticipated geological problems; availability of required drilling rigs, materials and equipment; 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 Penn Virginia's oil and natural gas production and PVR's lessees' mining operations; environmental risks affecting the drilling and producing of oil and gas wells or the mining of coal reserves; the timing of receipt of necessary governmental permits by Penn Virginia and by PVR's lessees; 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; uncertainties relating to the outcome of mountaintop removal; risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions; and the experience and financial condition of lessees of PVR's coal reserves including their ability to satisfy their royalty, environmental, reclamation and other obligations to PVR and others. Many of such factors are beyond Penn Virginia's ability to control or accurately predict. Readers are cautioned not to put undue reliance on forward-looking statements.

While Penn Virginia periodically reassesses material trends and uncertainties affecting Penn Virginia's 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 Penn Virginia's quarterly, annual and other reports filed with the SEC, Penn Virginia does 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) Evaluation of Disclosure Controls and Procedures:

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 Controls

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

PART II. Other Information

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

Item 4. Submission of Matters to a Vote of Security Holders

(a) The annual meeting of shareholders of Penn Virginia Corporation was held on May 6, 2003.

(b) All director nominees were elected as described in Item 4(c).

(c) The shareholders voted upon the election of directors as follows:

Director	Votes Received	Votes Withheld
Edward B. Cloues, II	6,685,360	1,066,873
A. James Dearlove	6,689,158	1,063,075
Robert Garrett	6,666,233	1,086,000
H. Jarrell Gibbs	6,685,158	1,067,075
Keith D. Horton	6,689,360	1,062,873
Marsha R. Perelman	6,685,360	1,066,873
Joe T. Rye	6,667,114	1,085,119
Gary K. Wright	6,749,058	1,003,175

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

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

(b) Reports on Form 8-K

The Company filed a report on Form 8-K on May 8, 2003 announcing that it had issued a press release regarding its financial results for the three months ended March 31, 2003.

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 8, 2003

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

Date: August 8, 2003

By: /s/ Dana G Wright
Dana G Wright, Vice President and
Principal Accounting Officer

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 quarterly 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.

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Date: August 8, 2003

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

Exhibit 31.2

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

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

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

2. Based on my knowledge, this quarterly 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 quarterly 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 8, 2003

/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, 2003 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.

August 8, 2003

/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, 2003 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.

August 8, 2003

/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.