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 September 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 November 3, 2003, 9,007,436 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 September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Revenues:				
Natural gas	$ 23,293	$ 16,012	$ 79,197	$ 43,032
Oil and condensate	5,372	2,085	13,999	5,954
Coal royalties	11,960	8,253	35,658	23,437
Timber	80	360	829	1,441
Other	1,316	2,044	4,057	4,921
Total revenues	**42,021**	**28,754**	**133,740**	**78,785**
Expenses:				
Lease operating	4,092	3,417	11,965	8,799
Exploration	3,752	1,682	11,714	3,846
Taxes other than income	2,854	1,653	8,922	4,775
General and administrative	6,302	5,406	18,140	15,303
Impairment of oil and gas properties	-	501	-	501
Depreciation, depletion and amortization	12,265	8,146	36,623	21,758
Total expenses	**29,265**	**20,805**	**87,364**	**54,982**
Operating income	**12,756**	**7,949**	**46,376**	**23,803**
Other income (expense):				
Interest expense	(1,380)	(868)	(3,837)	(1,988)
Interest income	301	508	951	1,583
Income from continuing operations before minority interest, income taxes, discontinued operations and cumulative effect of change in accounting principle	**11,677**	**7,589**	**43,490**	**23,398**
Minority interest in Penn Virginia Resource Partners, L.P.	2,936	3,379	8,778	9,321
Income tax expense	3,298	1,002	13,784	4,557
Income from continuing operations before discontinued operations and cumulative effect of change in accounting principle	**5,443**	**3,208**	**20,928**	**9,520**
Income from discontinued operations (including gain on sale and net of taxes)	-	-	-	221
Cumulative effect of change in accounting principle	-	-	1,363	-
Net income	**$ 5,443**	**$ 3,208**	**$ 22,291**	**$ 9,741**
Income before cumulative effect of change in accounting principle, basic	$0.61	$0.36	$2.33	$1.07
Income from discontinued operations, basic	-	-	-	0.02
Cumulative effect of change in accounting principle, basic	-	-	0.15	-
Net income per share, basic	**$0.61**	**$0.36**	**$2.48**	**$1.09**
Income before cumulative effect of change in accounting principle, diluted	$0.60	$0.36	$2.32	$1.07
Income from discontinued operations, diluted	-	-	-	0.02
Cumulative effect of change in accounting principle, diluted	-	-	0.15	-
Net income per share, diluted	**$0.60**	**$0.36**	**$2.47**	**$1.09**
Weighted average shares outstanding, basic	**8,996**	**8,944**	**8,974**	**8,926**
Weighted average shares outstanding, diluted	**9,069**	**8,992**	**9,032**	**8,975**

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

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

	September 30, 2003 (unaudited)	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 9,887	$ 13,341
Accounts receivable	32,627	20,366
Current portion of long-term notes receivable	697	527
Hedging assets	316	-
Other	1,236	1,503
Total current assets	**44,763**	**35,737**
Property and equipment		
Oil and gas properties (successful efforts method)	481,369	383,360
Other property and equipment	270,326	265,180
Less: Accumulated depreciation, depletion and amortization	(136,506)	(102,588)
Net property and equipment	**615,189**	**545,952**
Other assets	4,923	4,603
Total assets	**$ 664,875**	**$ 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)

	September 30, 2003 (unaudited)	December 31, 2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 1,500	$ 52
Accounts payable	1,311	5,670
Accrued liabilities	25,219	16,508
Hedging liabilities	1,849	1,621
Total current liabilities	**29,879**	**23,851**
Other liabilities	13,699	12,230
Hedging liabilities	392	444
Deferred income taxes	73,538	62,154
Long-term debt	58,000	16,000
Long-term debt of Penn Virginia Resource Partners, L.P.	90,696	90,887
Minority interest in Penn Virginia Resource Partners, L.P.	192,017	192,770
Shareholders' equity		
Preferred stock of $100 par value- authorized 100,000 shares; none issued	-	-
Common stock of $6.25 par value 16,000,000 shares authorized; 9,007,348 and 8,946,651 shares issued at September 30, 2003 and December 31, 2002 respectively	56,295	55,915
Other paid in capital	13,208	11,436
Retained earnings	139,417	123,189
Accumulated other comprehensive income	(1,373)	(1,661)
	207,547	188,879
Less: Unearned compensation and ESOP	893	923
Total shareholders' equity	**206,654**	**187,956**
Total liabilities and shareholders' equity	**$ 664,875**	**$ 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)

	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Cash flow from operating activities:		
Net income	$ 22,291	$ 9,741
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	36,623	21,758
Impairment of oil and gas properties	-	501
Minority interest	8,778	9,321
Cumulative effect of change in accounting principle	(1,363)	-
Deferred income taxes	10,495	6,101
Dry hole and unproved leasehold expense	4,098	149
Other	1,363	1,169
Changes in operating assets and liabilities:		
Current assets	(11,994)	(1,187)
Current liabilities	(1,333)	(7,648)
Other assets	(147)	(736)
Other liabilities	2,093	2,079
Net cash flows provided by operating activities	**70,904**	**41,248**
Cash flows from investing activities:		
Payments received on long-term notes receivable	381	445
Proceeds from sale of properties and equipment	166	1,314
Proceeds from sale of U.S. Treasury Notes	-	12,000
Additions to property and equipment	(98,083)	(45,739)
Net cash flows used in investing activities	**(97,536)**	**(31,980)**
Cash flows from financing activities		
Dividends paid	(6,061)	(6,027)
Distributions paid to minority interest holders	(14,566)	(10,041)
Net proceeds from (repayments of) PVA borrowings	41,948	6,280
Proceeds from PVR senior unsecured notes	90,000	-
Repayments of PVR revolving credit facility	(88,387)	-
Payments for debt issuance costs	(1,419)	-
Purchase of PVR units	-	(1,067)
Purchase of treasury stock	-	(557)
Issuance of stock	1,663	1,900
Net cash provided by (used in) financing activities	**23,178**	**(9,512)**
Net decrease in cash and cash equivalents	**(3,454)**	**(244)**
Cash and cash equivalents-beginning of period	**13,341**	**9,621**
Cash and cash equivalents-end of period	**$ 9,887**	**$ 9,377**
Supplemental disclosures of cash flow information:		
Cash paid during the periods for:		
Interest (net of amounts capitalized)	$ 3,668	$ 1,300
Income taxes	$ 6,348	$ 113

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

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 nine months ended September 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 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 September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income, as reported	$ 5,443	$ 3,208	$ 22,291	$ 9,741
Add: Stock-based employee compensation expense included in reported net income related to restricted units and director compensation, net of related tax effects	52	44	276	254
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(244)	(311)	(877)	(952)
Pro forma net income	$ 5,251	$ 2,941	$ 21,690	$ 9,043
Earnings per share				
Basic - as reported	$0.61	$0.36	$2.48	$1.09
Basic - pro forma	$0.58	$0.33	$2.42	$1.01
Diluted - as reported	$0.60	$0.36	$2.47	$1.09
Diluted - pro forma	$0.58	$0.33	$2.40	$1.01

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 September 30, 2003 (in thousands).

Balance, January 1, 2003	$ -
Initial adoption entry	2,685
Liabilities incurred in the current period	377
Liabilities settled in the current period	(17)
Accretion expense	115
Balance, September 30, 2003	$ 3,160

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

	Three Months Ended September 30, 2002	Nine Months Ended September 30 2002
Net income		
As reported	$3,208	$9,741
Pro forma	$3,229	$9,804
Net income per share - reported		
Basic	$0.36	$1.09
Diluted	$0.36	$1.09
Net income per share - pro forma		
Basic	$0.36	$1.09
Diluted	$0.36	$1.09

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 highly effective, 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 September 30, 2003. The following table sets forth our positions as of September 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			
October 1, 2003 - December 31, 2003	5,000	$5.00 / $7.10	$ 165
October 1, 2003 - April 30, 2004	7,272	$3.50 / $5.00	(758)
October 1, 2003 - June 30, 2004	7,500	$3.50 / $5.28	(658)
October 1, 2003 - July 31, 2004	4,000	$3.72 / $6.97	(66)
July 1, 2004 - October 31, 2004	7,000	$4.00 / $5.24	(167)
August 1, 2004 - October 31, 2004	4,000	$4.00 / $5.25	(74)
May 1, 2004 - November 30, 2004	6,500	$4.00 / $6.87	151
November 1, 2004 – January 31, 2005	9,212	$4.00 / $6.82	(14)
Swaps			
October 1 , 2003 - January 31, 2005	1,100 to 5,300	$4.70	(152)
Crude Oil	**(Bbls per Day)**	**(Per Bbl)**	
Swaps			
October 1, 2003 - September 30, 2004	120	$26.58	(38)
October 1, 2003 - January 1, 2005	50 to 250	$26.93	(10)
Total			$ (1,621)

Based upon our assessment of our derivative contracts designated as cash flow hedges at September 30, 2003, we reported (i) a hedging liability of approximately $1.9 million, a hedging asset of approximately $0.3 million and (ii) a loss in accumulated other comprehensive income of $1.1 million, net of a related income tax benefit of $0.5 million. In connection with monthly settlements, we recognized net hedging losses in natural gas and oil revenues of $0.7 million and $6.2 million for the three months and nine months ended September 30, 2003, respectively. Based upon future oil and natural gas prices as of September 30, 2003, $1.6 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 $0.7 million and $0.4 million for the three months and nine months ended September 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 a decrease of long-term debt of approximately $0.3 million as of September 30, 2003, with a corresponding increase in long-term hedging liabilities. 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 September 30, 2003 and December 31, 2002, long-term debt consisted of the following (in thousands):

	September 30, 2003 (Unaudited)	December 31, 2002
Penn Virginia revolving credit facility	$ 58,000	$ 16,000
PVR senior unsecured notes *	89,696	-
PVR revolving credit facility	2,500	47,500
PVR term loan	-	43,387
Line of credit	-	52
	150,196	106,939
Less: current maturities	(1,500)	(52)
Total long-term debt	$ 148,696	$ 106,887

***** Includes negative fair value adjustment of $304 thousand related to interest rate swap designated as a fair value hedge.

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. The Revolver is governed by a borrowing base calculation currently set at $150 million and is subject to a semi-annual redetermination. 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

On October 31, 2003 the Partnership entered into an amendment to its revolving credit facility (the "PVR Revolver") to increase the facility from $50 million to $100 million and to extend the maturity date to October 2006. The PVR Revolver is 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. At September 30, 2003, letters of credit issued were $1.6 million.

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 2.25 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 $43.4 million under a PVR term loan and the majority of the debt outstanding under the PVR Revolver.

The 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, to which PVR is currently in compliance.

Line of Credit

We have a $5 million line of credit, which had no borrowings against it as of September 30, 2003. The line of credit renews annually.

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 September 30, 2003, based on a range of probable payment amounts, we have recognized a cumulative liability of approximately $3.7 million for services rendered in connection with this agreement, of which $0.8 million and $2.4 million were recognized in general and administrative expense for the three and nine months ended September 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 September 30, 2003 and 2002 (in thousands, except share data).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Income from continuing operations	$ 5,443	$ 3,208	$ 20,928	$ 9,520
Income from discontinued operations	-	-	-	221
Cumulative effect of change in accounting principle	-	-	1,363	-
Net income	$ 5,443	$ 3,208	$ 22,291	$ 9,741
Weighted average shares, basic	8,996	8,944	8,974	8,926
Dilutive securities:				
Stock options	73	48	58	49
Weighted average shares, diluted	9,069	8,992	9,032	8,975
Income from continuing operations per share, basic	$ 0.61	$ 0.36	$ 2.33	$ 1.07
Income from discontinued operations per share, basic	-	-	-	0.02
Cumulative effect of change in accounting principle, basic	-	-	0.15	-
Net income per share, basic	$ 0.61	$ 0.36	$ 2.48	$ 1.09
Income from continuing operations per share, diluted	$ 0.60	$ 0.36	$ 2.32	$ 1.07
Income from discontinued operations per share, diluted	-	-	-	0.02
Cumulative effect of change in accounting principle, diluted	-	-	0.15	-
Net income per share, diluted	$ 0.60	$ 0.36	$ 2.47	$ 1.09

Options to purchase approximately 10,000 and 92,000 shares of common stock were not included in our computation of diluted earnings per share for the third quarter of 2003 and 2002, respectively, because their inclusion would have been anti-dilutive.

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 nine-month periods ended September 30, 2003 and 2002, the components of comprehensive income are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income	$ 5,443	$ 3,208	$ 22,291	$ 9,741
Unrealized gains (losses) on hedging activities, net of tax	(1,876)	(332)	(3,752)	(3,034)
Reclassification adjustment for hedging activities, net of tax	470	427	4,040	234
Comprehensive income	$ 4,037	$ 3,303	$ 22,579	$ 6,941

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 September 30, 2003:				
Revenues	$29,035	$12,812	$ 174	$42,021
Operating costs and expenses	11,411	2,803	2,786	17,000
Depreciation, depletion and amortization	8,572	3,659	34	12,265
Operating income (loss)	$ 9,052	$ 6,350	$(2,646)	12,756
Interest expense				(1,380)
Interest income				301
Income before minority interest and taxes				$11,677
Additions to property and equipment	$20,770	$ 1,991	$ 215	$22,976
For the three months ended September 30, 2002:				
Revenues	$18,182	$10,404	$ 168	$28,754
Operating costs and expenses	7,823	2,370	1,965	12,158
Impairment of oil and gas properties	501	-	-	501
Depreciation, depletion and amortization	7,098	995	53	8,146
Operating income (loss)	$ 2,760	$ 7,039	$(1,850)	7,949
Interest expense				(868)
Interest income				508
Income before minority interest and taxes				$ 7,589
Additions to property and equipment	$12,329	$12,106	$ 42	$24,477

	Oil and Gas	Coal Royalty and Land Management	All Other	Total
	(in thousands)			
For the nine months ended September 30, 2003:				
Revenues	$ 93,791	$39,334	$ 615	$133,740
Operating costs and expenses	33,812	8,665	8,264	50,741
Depreciation, depletion and amortization	24,493	12,027	103	36,623
Operating income (loss)	$ 35,486	$18,642	$(7,752)	46,376
Interest expense				(3,837)
Interest income				951
Income before minority interest and taxes				$43,490
Additions to property and equipment	$ 94,094	$ 3,437	$ 552	$98,083
For the nine months ended September 30, 2002:				
Revenues	$ 49,176	$28,950	$ 659	$78,785
Operating costs and expenses	20,086	7,207	5,430	32,723
Impairment of oil and gas properties	501	-	-	501
Depreciation, depletion and amortization	19,041	2,558	159	21,758
Operating income (loss)	$ 9,548	$19,185	$(4,930)	23,803
Interest expense				(1,988)
Interest income				1,583
Income before minority interest and taxes				$23,398
Additions to property and equipment	$ 32,542	$ 12,887	$ 310	$45,739

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 September 30, 2003.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets" to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas 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 the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, we would be required to reclassify approximately $132 million, $105 million and $113 million at September 30, 2003, December 31, 2002 and December 31, 2001, respectively, out of oil and gas properties and into a separate line item for intangible assets. Our cash flows and 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 the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on our compliance with covenants under our debt agreements.

Regarding PVR, the Emerging Issues Task Force ("EITF") is 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 EITF 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, we have included PVR's owned and leased mineral interests as a component of property and equipment on the balance sheet. It is possible that it will be determined 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 responsible accounting authorities are 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 June 30, 2001, the 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: (1) oil and gas and (2) coal royalty and land management. The oil and gas segment includes the ownership of mineral rights to oil and gas reserves and 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. The coal royalty and land management segment operated by Penn Virginia Resource Partners, L.P. (the "Partnership" or "PVR") includes the leasing of coal reserves, providing of services to coal mining companies through fee-based assets, and the sale of timber. The assets, liabilities and earnings of PVR are included in our consolidated financial statements, with the public unitholders' approximate 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. As of September 30, 2003 unproved leasehold costs amounted to $60.0 million.

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 or declining balance methods 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 net book value 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. Revenues associated with sales of crude oil, condensate, natural gas, and natural gas liquids are recorded when title passes to the customer. Natural gas sales revenues from properties in which the Company has an interest with other producers are recognized on the basis of our net working interest ("entitlement" method of accounting). Natural gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company takes less than it is entitled, the under-delivery is recorded as a receivable.

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 70 percent 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 2003 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 highly effective, 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 September 30, 2003 Compared to Three Months Ended September 30, 2002

We reported net income of $5.4 million, or $0.60 per share (diluted), for the three months ended September 30, 2003, compared with $3.2 million, or $0.36 per share (diluted), for the three months ended September 30, 2002. Revenues increased $13.3 million, primarily as a result of increased natural gas and crude oil prices received and increased production of crude oil and coal. Total expenses were $8.5 million higher during the three months ended September 30, 2003 than in the 2002 comparable period, primarily due to our acquisition of certain south Texas oil and gas properties, and PVR's acquisition of certain coal reserves subsequent to the third quarter of last year. 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 $6.3 million for the three months ended September 30, 2003, compared with $5.4 million for the same period in 2002. The $0.9 million increase was due primarily to a general increase in staffing, insurance premiums and consulting and advisory services.

Interest expense. On a consolidated basis, interest expense was $1.4 million for the three months ended September 30, 2003, compared with $0.9 million for the same period in 2002, an increase of $0.5 million or 59 percent. The increase was primarily due to increased debt levels in connection with coal and oil and gas property acquisitions in late 2002 and early this year.

Interest income. Interest income was $0.3 million for the three months ended September 30, 2003, compared with $0.5 million for the same period in 2002. The decrease was primarily due to PVR's liquidation of U.S. Treasury Notes during the last half of 2002.

Minority interest. Minority interest for the three months ended September 30, 2003 was $2.9 million, compared to $3.4 million for the same period in 2002. The decrease was primarily due to a decrease in PVR's net income for the comparable periods, offset by a decrease in the Company's ownership percentage in the Partnership.

Income taxes. The effective tax rate for the three months ended September 30, 2003 was 38 percent, compared to 24 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 - Nine Months Ended September 30, 2003 Compared to Nine Months Ended September 30, 2002

We reported net income of $22.3 million, or $2.47 per share (diluted), for the nine months ended September 30, 2003, compared with $9.7 million, or $1.09 per share (diluted), for the nine months ended September 30, 2002. Revenues increased $55.0 million, primarily as a result of increased natural gas and crude oil prices received and increased production of natural gas, crude oil and coal. Total expenses were $32.4 million higher during the nine months ended September 30, 2003 than in the 2002 comparable period, primarily due to our acquisition of certain south Texas oil and gas properties, and PVR's acquisition of certain coal reserves subsequent to September 30, 2002. 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 $18.1 million for the nine months ended September 30, 2003, compared with $15.3 million for the same period in 2002. The $2.8 million increase was due primarily to consulting and advisory services and legal fees related to the consideration of various shareholder proposals, a general increase in the staffing levels for the Company and higher insurance premiums.

Interest expense. On a consolidated basis, interest expense was $3.8 million for the nine months ended September 30, 2003, compared with $2.0 million for the same period in 2002, an increase of $1.8 million or 93 percent. The increase was primarily due to increased debt levels in connection with coal and oil and gas property acquisitions in late 2002 and early this year.

Interest income. Interest income was $1.0 million for the nine months ended September 30, 2003, compared with $1.6 million for the same period in 2002. The decrease was primarily due to PVR's liquidation of U.S. Treasury Notes during the last half of 2002.

Minority interest. Minority interest for the nine months ended September 30, 2003 was $8.8 million, compared to $9.3 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 by a decrease in the Company's ownership percentage in the Partnership.

Income taxes. The effective tax rate for the nine month period ended September 30, 2003 was 40 percent, compared to 32 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"). The properties were acquired in a cash transaction with a private investor group for $32.5 million. 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. Ten successful wells and one dry hole have been drilled in the field since the acquisition date. 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 subsequent 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"). 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 September 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 this property, which PVR now refers to as its Coal River Property, filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. Coal River'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 Coal River, 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, including the infrastructure, in May 2003 and assigned all reclamation and mitigation liabilities to the new lessee. The new lessee began operations in the third quarter of 2003.

During the three and nine months ended September 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 $9.1 million for the three months ended September 30, 2003, compared with $2.8 million for the comparable period of 2002. Operational and financial data for the Company's oil and gas segment for the three months ended September 30, 2003 and 2002 is summarized as follows:

	Three Months Ended September 30,			
Production	2003		2002 **	
Natural gas (MMcf)	4,728		5,008	
Oil and condensate (MBbls)	216		91	
Total equivalent production (MMcfe)	6,024		5,554	
	(in thousands)	($ per unit)	(in thousands)	($ per unit)
Revenues:				
Natural gas * (including $/Mcf)	$ 23,293	$ 4.93	$ 16,012	$ 3.20
Oil and condensate * (including $/Bbl)	5,372	24.87	2,085	22.91
Other income	370		85	
Total revenues (including $/Mcfe)	29,035	4.82	18,182	3.27
Expenses (including $/Mcfe):				
Lease operating	3,195	0.53	2,712	0.49
Exploration	3,747	0.62	1,614	0.29
Taxes other than income	2,364	0.39	1,355	0.24
General and administrative	2,105	0.35	2,142	0.39
Impairment of oil and gas properties	-	-	501	0.09
Depreciation, depletion and amortization	8,572	1.42	7,098	1.28
Total expenses	19,983	3.31	15,422	2.78
Operating income (including $/Mcfe)	$ 9,052	$ 1.51	$ 2,760	$ 0.49

*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 September 30, 2003, approximately 54 percent of our natural gas and 11 percent of our crude oil production was hedged at an average floor price of $3.69 per MMbtu and ceiling price of $5.51 per MMbtu for natural gas, and an average swap price of $26.76 per barrel for crude oil. The effects of these hedges were to decrease the average natural gas prices received by $0.13 per Mcf and the average crude oil prices received by $0.45 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 and in accordance with our risk management policy, circumstances warrant.

Natural gas. Natural gas sales increased by $7.3 million, or 45 percent, for the three months ended September 30, 2003, compared with the same period of 2002. The average natural gas price received was 54 percent higher in the third quarter of 2003, compared with the same quarter of the prior year. Offsetting the price increase, was a slight production decrease of 280 MMcf, or 6 percent, in the third quarter of 2003 compared with the same period in 2002. The production decrease was primarily related to reduced performance of older wells offset somewhat by new production from the south Texas acquisition and the drilling program.

Oil and condensate. Oil sales increased by $3.3 million for three months ended September 30, 2003, compared with the same period of 2002. The increase was primarily due to increased production of 125 MBbls related to the south Texas acquisition in January 2003. Average realized prices received for crude oil production also increased by $1.96 per barrel, or nine percent.

Lease operating expenses. Operating expenses for the three months ended September 30, 2003 were $3.2 million, compared with $2.7 million in the comparable period of 2002. The $0.5 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 $0.1 million of the increase associated with well workover costs in various fields.

Exploration expenses. Exploration expenses for the three months ended September 30, 2003 increased to $3.7 million, compared with $1.6 million in the comparable period of 2002. The increase was primarily due to amounts expensed related to unsuccessful exploratory wells during the third quarter of 2003.

Taxes other than income. Taxes other than income increased to $2.4 million for three months ended September 30, 2003 from $1.4 million in the third quarter of 2002. The increase was primarily due to higher prices received for natural gas and crude oil, as well as increased crude oil production in the third quarter of 2003 as compared to the same period in 2002.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the three months ended September 30, 2003 increased to $8.6 million, compared with $7.1 million in the comparable period of 2002. The increase was primarily due to higher depletion rates and production.

Operating income for the oil and gas segment was $35.5 million for the nine months ended September 30, 2003, compared with $9.5 million for the comparable period of 2002. Operational and financial data for the Company's oil and gas segment for the nine months ended September 30, 2003 and 2002 is summarized as follows:

	Nine Months Ended September 30,			
Production	2003		2002 **	
Natural gas (MMcf)	14,516		13,916	
Oil and condensate (MBbls)	526		259	
Total equivalent production (MMcfe)	17,672		15,470	
	(in thousands)	($ per unit)	(in thousands)	($ per unit)
Revenues:				
Natural gas * (including $/Mcf)	$79,197	$ 5.46	$43,032	$ 3.09
Oil and condensate * (including $/Bbl)	13,999	26.61	5,954	22.99
Other income	595		190	
Total revenues (including $/Mcfe)	93,791	5.31	49,176	3.18
Expenses (including $/Mcfe):				
Lease operating	9,094	0.51	6,475	0.42
Exploration	11,648	0.66	3,663	0.24
Taxes other than income	7,446	0.42	3,922	0.25
General and administrative	5,624	0.32	6,026	0.39
Impairment of oil and gas properties	-	-	501	0.03
Depreciation, depletion and amortization	24,493	1.39	19,041	1.23
Total expenses	58,305	3.30	39,628	2.56
Operating income (including $/Mcfe)	$35,486	$ 2.01	$ 9,548	$ 0.62

*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 nine months ended September 30, 2003, approximately 47 percent of our natural gas and 27 percent of our crude oil production was hedged at an average floor price of $3.59 per MMbtu and ceiling price of $5.33 per MMbtu for natural gas, and an average floor price of $24.41 per barrel and ceiling price of $28.06 per barrel for crude oil. The effects of these hedges were to decrease the average natural gas prices received by $0.40 per Mcf and the average crude oil prices received by $0.90 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 and in accordance with our risk management policy, circumstances warrant.

Natural gas. Natural gas sales increased by $36.2 million, or 84 percent, for the nine months ended September 30, 2003, compared with the same period of 2002. The average natural gas price received was 77 percent higher in 2003, compared with the same period in 2002. In addition, production increased 600 MMcf, or four percent, in the 2003 compared with the same period in 2002. The production increase primarily related to the south Texas acquisition and the drilling programs in 2002 and 2003 more than offset production decline in older wells.

Oil and condensate. Oil sales increased by $8.0 million for the nine months ended September 30, 2003, compared with the same period of 2002. The increase was primarily due to increased production of 267 MBbls related primarily to the south Texas acquisition in January 2003. Average realized prices received for crude oil production also increased by $3.62 per barrel, or 16 percent.

Lease operating expenses. Operating expenses for the nine months ended September 30, 2003, were $9.1 million, compared with $6.5 million in the comparable period of 2002. The $2.6 million increase relates primarily 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 $1.0 million of the increase associated with maintenance and workover costs in various fields.

Exploration expenses. Exploration expenses for the nine months ended September 30, 2003 increased to $11.6 million, compared with $3.7 million in the comparable period of 2002. The increase was primarily due to amounts expensed on account of unsuccessful exploratory wells and the purchase of seismic data to evaluate both existing and new prospects during 2003.

Taxes other than income. Taxes other than income increased to $7.4 million for the nine months ended September 30, 2003 from $3.9 million in the comparable period of 2002. The increase was primarily due to higher prices received for natural gas and crude oil, as well as increased production in 2003 as compared to the same period in 2002.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the nine months ended September 30, 2003 increased to $24.5 million, compared with $19.0 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 September 30, 2003 compared with the same period in 2002.

Financial Highlights:	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Percentage Change
	(in thousands, except prices)		
Revenues:			
Coal royalties	$ 11,960	$ 8,253	45%
Coal services	484	476	2%
Timber	80	360	(78%)
Minimum rentals	220	1,079	(80%)
Other	68	236	(71%)
Total revenues	12,812	10,404	23%
Operating costs and expenses:			
Operating	753	555	36%
Taxes other than income	389	241	61%
General and administrative	1,661	1,574	6%
Depreciation, depletion and amortization	3,659	995	268%
Total operating costs and expenses	6,462	3,365	92%
Operating income	$ 6,350	$ 7,039	(10%)

Coal royalties. Coal royalty revenues for the three months ended September 30, 2003 were $12.0 million compared to $8.3 million for the same period in 2002, an increase of $3.7 million, or 45 percent, while production by PVR lessees increased 2.5 million tons, or 68 percent. The Peabody and Upshur Acquisitions in the last half of 2002 accounted for $3.0 million, or 2.3 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 PVR's leases with subsidiaries of Peabody Energy Corporation (the "Peabody Leases").

Coal services. Coal services revenues remained constant at $0.5 million for the three months ended September 30, 2003 and 2002. The coal service facility at the recently leased PVR Coal River property in West Virginia began operations late in the third quarter of 2003.

Timber sales. Timber revenues decreased to $0.1 milllion for the three months ended September 30, 2003, compared with $0.4 million in the third quarter of 2002, a decrease of $0.3 million, or 78 percent. Volume sold declined 1,233 thousand board feet (Mbf), or 73 percent, to 457 Mbf in the third quarter of 2003, compared with 1,690 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 decreased to $0.2 million for the three months ended September 30, 2003 from $1.1 million in the comparable period of 2002, a decrease of $0.9 million, or 80 percent. The decrease was primarily due to a lessee rejecting a PVR lease in bankruptcy on August 31, 2002; consequently, all deferred revenue from this respective lessee ($0.8 million) was recognized as income. The remainder of the decrease was primarily due to the timing of expiring recoupments from our lessees.

Other income. Other income decreased to $0.1 million for the three months ended September 30, 2003, compared with $0.2 million for the same period in 2002. The $0.1 million decrease is 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. Other income primarily consists of land rental and wheelage income, which are fees received by PVR for transportation across our surface property.

Operating expenses. Operating expenses increased by 36 percent, to $0.8 million in the third quarter of 2003, compared with $0.6 million in the same period of 2002. The $0.2 million increase is due to increased production on PVR subleased properties and additional maintenance on PVR unleased property. PVR leased the Coal River 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 for the three months ended September 30, 2003 increased to $0.4 million, representing a $0.1 million, or 61 percent, increase over the comparable period in 2002. The increase was primarily attributable to additional West Virginia property taxes relating to the Coal River property. PVR leased the Coal River 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 $0.1 million, or 6 percent, to $1.7 million in the third quarter of 2003, from $1.6 million in the same period of 2002. The increase was primarily attributable to increased payroll, 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 September 30, 2003 was $3.7 million compared with $1.0 million for the same period of 2002, an increase of 268 percent. This increase is 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 in the last half of 2002.

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

	Nine Months Ended September 30,		**Percentage**
Financial Highlights:	**2003**	**2002**	**Change**
	(in thousands, except prices)		
Revenues:			
Coal royalties	$ 35,658	$ 23,437	52%
Coal services	1,523	1,353	13%
Timber	829	1,441	(42%)
Minimum rentals	1,035	1,979	(48%)
Other	289	740	(61%)
Total revenues	39,334	28,950	36%
Operating costs and expenses:			
Operating	2,488	1,886	32%
Taxes other than income	978	663	48%
General and administrative	5,199	4,658	12%
Depreciation, depletion and amortization	12,027	2,558	370%
Total operating costs and expenses	20,692	9,765	112%
Operating income	$ 18,642	$ 19,185	(3%)

Coal royalties. Coal royalty revenues for the nine months ended September 30, 2003 were $35.7 million compared to $23.4 million for the same period in 2002, an increase of $12.3 million, or 52 percent, while production by PVR lessees increased 8.6 million tons, or 81 percent. The Peabody and Upshur Acquisitions in the last half of 2002 accounted for $11.5 million, or 8.4 million tons, of the increase 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 $0.36, or 16 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 13 percent, to $1.5 million for the nine months ended September 30, 2003, compared with $1.4 million in the same period of 2002. The slight increase was attributable to small preparation plants which PVR leased to two of its lessees. The coal service facility at the recently leased PVR Coal River property in West Virginia began operations late in the third quarter of 2003.

Timber sales. Timber revenues decreased to $0.8 million for the nine months ended September 30, 2003, compared with $1.4 million in the comparable period of 2002, a decrease of $0.6 million, or 42 percent. Volume sold declined 3,154 Mbf, or 42 percent, to 4,338 Mbf in the first nine months of 2003, compared with 7,492 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 decreased $1.0 million, or 48 percent, to $1.0 million for the nine months ended September 30, 2003 from $2.0 million in the comparable period of 2002. The decrease was primarily due to a lessee rejecting a PVR lease in bankruptcy on August 31, 2002; consequently, all deferred revenue from this respective lessee ($0.8 million) was recognized as income. The remainder of the decrease was primarily due to the timing of expiring recoupments from PVR's lessees.

Other income. Other income decreased to $0.3 million for the nine months ended September 30, 2003, compared with $0.7 million for the same period in 2002. The $0.4 million, or 61 percent, decrease is 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 32 percent, to $2.5 million, for the nine months ended September 30, 2003, compared with $1.9 million in the same period of 2002. The increase is due to the cost of maintaining an idle mine on PVR's Coal River property. PVR leased the Coal River 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 48 percent, to $1.0 million for the nine months ended September 30, 2003, compared with $0.7 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 Coal River 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 Coal River 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 $0.5 million, or 12 percent, to $5.2 million for the nine months ended September 30, 2003, from $4.7 million in the same period of 2002. The increase was primarily attributable to increased payroll, an increase in insurance premiums and additional recurring expenses associated with the Peabody Acquisition.

Depreciation, depletion and amortization. Depreciation, depletion and amortization for the nine months ended September 30, 2003 was $12.0 million compared with $2.6 million for the same period of 2002, an increase of 370 percent. This increase is 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 in 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 paid on the subordinated and common limited partner units it owns, currently comprising approximately 42.5 percent of PVR's ownership, and on its two percent general partnership interest in PVR. 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 through 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 $70.9 million for the nine months ended September 30, 2003, compared with $41.2 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 operating expenses. Production for the nine months ended September 30, 2003 was 17.7 Bcfe, or 14 percent higher than the same period of 2002, due primarily to our acquisition of a 25 percent working interest in the south Texas acquisition.

Cash Flows from Investing Activities

For the nine months ended September 30, 2003, we used $97.5 million in investing activities, compared with $32.0 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. For the nine months ended September 30, 2002, the Company benefited from the sale of $12.0 million of the U.S. Treasury Notes.

Capital expenditures totaled $110.9 million for the nine months ended September 30, 2003, compared with $49.0 million in the same period in 2002. The following table sets forth capital expenditures made during the periods indicated.

	Nine Months Ended September 30,	
	2003	2002
	(in thousands)	
Oil and gas		
Development drilling	$45,347	$25,271
Exploratory drilling	8,871	1,057
Lease acquisitions	41,739	4,446
Field projects	3,433	1,489
Seismic and other	7,505	3,578
Oil and gas capital expenditures	106,895	35,841
Coal royalty and land management (PVR)		
Lease acquisitions	1,361	12,110
Support equipment and facilities	2,076	777
Coal royalty and land management capital expenditures	3,437	12,887
Other	552	310
Total capital expenditures	$110,884	$49,038

We drilled a total of 140 wells with 136 successes for the nine months ended September 30, 2003, compared to 74 wells with 71 successes in the same period in 2002. During the fourth quarter of 2003, we plan to drill approximately 40 gross wells, of which approximately 85 percent are expected to be development wells. Total capital expenditures for the oil and gas segment are expected to be approximately $25 million during the fourth quarter of 2003, and coal royalty and land management segment capital expenditures are expected to be approximately $1.5 million for the same period, primarily for the construction of a coal preparation plant on the Partnership's Coal River property.

Drilling activities for the oil and gas segment during the third quarter of 2003 are described in the following paragraphs.

Western Region Operations (Onshore Gulf Coast and West Texas)

On October 1, 2003, production commenced at the Company's M.A. Failla #1 well (37 percent working interest (W.I.)), a previously announced success located in the Broussard Field in Lafayette Parish, La. The well is currently producing at a gross rate of approximately 18.9 million cubic feet per day (Mmcfpd) and 480 barrels of oil per day (Bopd) or 6.1 Mmcfe per day net to PVA.

The Company drilled ten wells in its Western region during the third quarter of 2003, including seven development wells, six of which were successful, and three exploration wells with two successes. Two of the successful exploration wells were drilled in South Louisiana. The Hero Land Co. #1 well in the Stella Field, located in Plaquemines Parish, La., was completed in the Cris I sands and had a final test rate of 7.1 Mmcfpd of natural gas and 115 Bopd with a flowing tubing pressure of 3,122 pounds per square inch (psi). PVA has a 19.88 percent W.I. in the well. Production from this well and two previously announced exploration successes in the Stella Field is expected to commence by mid-November of 2003. The Nunez #1 well, in the South Creole Field in Cameron Parish, La., found pay in the Planulina O and J Sands. The Planulina O objective tested at a rate of 6.3 Mmcfpd of natural gas and 57 Bopd with a flowing tubing pressure of 8,801 psi. The Company has a 30 percent W.I. in the well and is currently awaiting completion of production facilities. A second well to develop the J Sand is currently in progress with production expected to commence around year-end 2003, and the Company is evaluating additional drilling prospects in the area. PVA drilled an unsuccessful Wilcox objective exploration well in the Tom Lyne Field in South Texas' Live Oak County, with a dry hole cost of $1.4 million net to the Company. In the first nine months of 2003, the Company has drilled 4 successful exploration wells in 6 attempts in the Western Region. In the fourth quarter of 2003, the Company expects to drill two or three exploration wells in the Western Region, including a well to test the Frio in the Company's Fannett Field in Jefferson County, Texas, a salt dome on which PVA recently completed a 3-D seismic survey, and a well to test the Vicksburg on the Company's Esperanza prospect in Nueces County, Texas. Drilling of this non-operated Vicksburg prospect at Esperanza (33 percent W.I.) has resulted in the Company deferring to 2004 the drilling of the PVA-operated Richard King prospect (100 percent W.I.), another of the Company's higher risk/return prospects, which is also located in Nueces County, Texas.

The Company drilled four development wells in the Vicksburg objective in the Southwest Kingsville Field during the third quarter. One of the wells was unsuccessful, with two intervals testing saltwater after stimulation. Until the unsuccessful well has been fully evaluated, the Company has deferred any new drilling in the field. The unsuccessful well and the drilling deferral have caused the Company to reduce its fourth quarter 2003 production estimate for the field. Additional development wells were drilled and are producing in the Ninock Field in Bossier Parish, La. (Cotton Valley), the Matthews Field in Reeves County, Texas (Brushy Canyon), and the Rugeley Field in Matagorda County, Texas (Frio). The Company expects to drill two or three additional development wells in the Western Region during the fourth quarter of 2003.

Eastern Region Operations (Appalachia and Mississippi)

PVA drilled 46 successful gross wells in as many attempts in its Eastern Region during the third quarter of 2003, including 45 development wells with an average W.I. of 73.9 percent and one coalbed methane (CBM) exploration well in Kansas with a 100 percent W.I. to the Company.

PVA drilled 26 gross successful Selma Chalk development wells in Mississippi during the third quarter of 2003. The Company has an average working interest of 99 percent in the wells and is the operator. PVA completed 55 gross Selma Chalk development wells in the first nine months of 2003 and plans to drill an additional 20 to 25 gross development wells in the fourth quarter. In the fourth quarter of 2003, production from the Company's Selma Chalk area is expected to increase over the third quarter of 2003 as a result of this active development program.

The Company drilled 14 gross conventional development wells in West Virginia, Virginia and Kentucky during the third quarter of 2003, with an average working interest of 58 percent. The Company operates five of these wells. During the fourth quarter of 2003, PVA plans to drill five to seven more conventional wells in its non-operated Roaring Fork field in Virginia.

PVA drilled five horizontal coalbed methane patterns in West Virginia during the third quarter, with an average working interest of 28 percent. Third quarter results included the Loup Creek 001C pattern (64 percent W.I.) in Wyoming County, WV, with a total lateral distance of approximately 17,000 feet in the Lower Beckley Coal. After drilling, this pattern tested at the rate of seven to eight Mmcf per day. The pattern is currently producing approximately two Mmcf per day until additional pipeline and compressor facilities can be constructed by PVA. Four additional horizontal CBM patterns are expected to be drilled in West Virginia during the fourth quarter of 2003, and fourth quarter CBM production is expected to increase over the third quarter of 2003.

During the third quarter of 2003, the Company drilled and completed an exploratory CBM well in the Cherokee Basin in Chase County, KS to test a portion of its approximately 45,000 acre leasehold position in the basin. Four offsets to the well are expected to be drilled by the end of 2003, which would result in a total of ten wells being drilled in the basin during 2003. Production rates from the wells are being tested and the Company expects to know commercial viability of the program during the first half of 2004.

Cash Flows from Financing Activities

Net cash provided by financing activities totaled $23.2 million for the nine months ended September 30, 2003, compared to net cash used in financing activities of $9.5 million for the same period in 2002. Credit facility borrowings provided approximately $43.6 million of cash from financing activities during 2003, offset in part by $6.1 million of dividend payments to PVA stockholders and distributions of $14.6 million to PVR's minority unitholders.

We have a $150 million secured revolving credit facility which expires in October 2004 (the "Revolver") with a group of major commercial banks. The Revolver is governed by a borrowing base calculation currently set at $150 million and is subject to a semi-annual redetermination. 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.

On October 31, 2003, the Partnership entered into an amendment to its revolving credit facility (the "PVR Revolver") to increase the facility from $50 million to $100 million and to extend the maturity date to October 2006. Available borrowing capacity under this facility was approximately $11 million as of September 30, 2003. The PVR Revolver is with a syndicate of financial institutions led by PNC Bank, National Association, as their agent. 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 2.25 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.

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

Surface Mining Valley Fills. Over the course of the last several years, opponents of surface mining have filed three lawsuits challenging the legality of permits authorizing the construction of valley fills for the disposal of coal mining overburden under federal and state laws applicable to surface mining activities. Although two of these challenges were successful in the United States District Court for the Southern District of West Virginia (the "District Court"), 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.

On October 23, 2003, a third lawsuit involving the disposal of coal mining overburden was filed under the name of Ohio Valley Environmental Coalition v. Bulen. In this case, which was also filed in the District Court, several public interest group plaintiffs have alleged that the Army Corps of Engineers violated the Clean Water Act

("CWA") and other federal regulations when it issued Nationwide Permit 21, a general permit for the disposal of coal mining overburden into United States waters. This most recent suit also challenges certain individual discharge authorizations in West Virginia, including several involving the mining activities of the Partnership's lessees. If the plaintiffs prevail in this latest lawsuit, lessees who have received authorization for discharges pursuant to Nationwide Permit 21 could be prevented from undertaking future discharges until they receive individual CWA permits, and future operations could require individual permits. Obtaining these individual permits is likely to substantially increase both the time and the costs of obtaining CWA permits for our lessees and other coal mining operators throughout the industry where any such unfavorable ruling may be applied. These increases could adversely affect our coal royalty revenues. Although the Partnership expects that any ruling for the plaintiffs would be appealed to the Fourth Circuit, the coal mining industry, including the operations of our lessees, could be significantly adversely impacted by the initial effects of an adverse decision while any appeal is pending.

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 September 30, 2003.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets" to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas 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 the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined by the accounting standard setters that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, we would be required to reclassify approximately $132 million, $105 million and $113 million at September 30, 2003, December 31, 2002 and December 31, 2001, respectively, out of oil and gas properties and into a separate line item for intangible assets. Our cash flows and 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 the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on our compliance with covenants under our debt agreements.

Regarding PVR, the Emerging Issues Task Force ("EITF") is 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 EITF 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, we have included PVR's owned and leased mineral interests as a component of property and equipment on the balance sheet. It is possible that it will be determined 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 responsible accounting authorities are 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 June 30, 2001, the 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 October 8, 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
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	13,656	$ 4.00	$ 6.52	379	$ 4.70
Second Quarter 2005 (April)	14,000	$ 4.00	$ 6.40	-	$ -

(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
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 September 30, 2003, we had open natural gas derivative positions with a fair value indicating a liability of $1.5 million. A 10 percent increase in natural gas prices would decrease the fair value by approximately $2.3 million to a fair value indicating a liability of $3.8 million. A 10 percent decrease in prices would increase the fair value by approximately $2.1 million to fair value indicating an asset of $0.6 million. We also had open oil price swap positions with a fair value indicating a liability 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 indicating a liability 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 indicating an asset of $0.1 million. Notional volumes and respective September 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 September 30, 2003, we had $58.0 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 us and PVR.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and PVR and, therefore, involve a number of risks and uncertainties. We caution 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 our operations or financial condition 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 and the cost to PVR of finding new coal reserves;
- our ability to acquire new oil and gas reserves and PVR's ability 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;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production;
- 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;
- 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 our oil and natural gas production and PVR's lessees' mining operations and related coal infrastructure projects;
- 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 us and by PVR's lessees;
- the risks associated with having or not having price risk management programs;
- labor relations and costs;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- uncertainties relating to the outcome of litigation regarding permitting of the disposal of coal overburden;
- risks and uncertainties relating to general domestic and international economic (including inflation and interest rates) and political conditions;
- 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; and
- the Partnership's ability to make cash distributions.

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

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

Item 4. Controls and Procedures

(a) 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, 4 and 5 are not applicable and have been omitted.

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 August 7, 2003 announcing that it had issued a press release regarding its financial results for the three months ended June 30, 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: November 7, 2003

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

Date: November 7, 2003

By: /s/ Dana G Wright
Dana G Wright, Vice President and Controller
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: November 7, 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: November 7, 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 September 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.

November 7, 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 September 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.

November 7, 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.