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

FORM 10-Q

[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2002

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

Oklahoma (State or other jurisdiction of incorporation or organization)	**73-1395733** (I.R.S. Employer Identification No.)
6100 North Western Avenue **Oklahoma City, Oklahoma** (Address of principal executive offices)	**73118** (Zip Code)

(405) 848-8000
Registrant's telephone number, including area code

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 [ ]

At November 4, 2002, there were 166,253,078 shares of our $.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2002

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2002	December 31, 2001
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 25,378	$ 117,594
Restricted cash	131	7,366
Accounts receivable:		
Oil and gas sales	82,908	51,496
Joint interest, net of allowance for bad debts of $1,321,000 and $947,000, respectively	19,617	17,364
Short-term derivatives	16,576	34,543
Related parties	2,198	9,896
Other	15,374	14,951
Short-term derivative instruments	843	97,544
Inventory and other	12,824	10,629
Total Current Assets	175,849	361,383
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	4,210,692	3,546,163
Unevaluated properties	68,995	66,205
Less: accumulated depreciation, depletion and amortization	(2,060,317)	(1,902,587)
	2,219,370	1,709,781
Other property and equipment	142,904	115,694
Less: accumulated depreciation and amortization	(44,561)	(39,894)
Total Property and Equipment	2,317,713	1,785,581
OTHER ASSETS:		
Long-term derivatives receivable	4,058	18,852
Deferred income tax asset	9,717	67,781
Long-term derivative instruments	—	6,370
Long-term investments	20,734	29,849
Other assets	16,562	16,952
Total Other Assets	51,071	139,804
TOTAL ASSETS	$ 2,544,633	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Notes payable and current maturities of long-term debt	$ —	$ 602
Accounts payable	83,860	79,945
Accrued interest	45,039	26,316
Short-term derivative instruments	22,348	—
Other accrued liabilities	59,463	36,998
Revenues and royalties due others	35,643	29,520
Total Current Liabilities	246,353	173,381
LONG-TERM DEBT, NET	1,494,180	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	14,191	12,696
LONG-TERM DERIVATIVE INSTRUMENTS	49,358	—
OTHER LIABILITIES	5,764	3,831
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 10,000,000 shares authorized; 2,998,000 and 3,000,000 shares of 6.75% cumulative convertible preferred stock issued and outstanding at September 30, 2002 and December 31, 2001, respectively, entitled in liquidation to $149.9 million and $150 million	149,900	150,000
Common Stock, $.01 par value, 350,000,000 shares authorized; 171,019,880 and 169,534,991 shares issued at September 30, 2002 and December 31, 2001, respectively	1,710	1,696
Paid-in capital	1,038,347	1,035,156
Accumulated deficit	(444,089)	(442,974)
Accumulated other comprehensive income, net of tax of $5,934,000 and $ 29,000,000, respectively	8,901	43,511
Less: treasury stock, at cost; 4,792,529 common shares at September 30, 2002 and December 31, 2001	(19,982)	(19,982)
Total Stockholders' Equity	734,787	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,544,633	$ 2,286,768

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 163,012	$ 177,746	$ 456,992	$ 574,190
Risk management income (loss)	(7,046)	32,260	(86,995)	94,715
Oil and gas marketing sales	42,216	28,905	112,334	123,071
Total Revenues	198,182	238,911	482,331	791,976
OPERATING COSTS:				
Production expenses	24,950	19,303	71,252	55,933
Production taxes	6,807	7,063	19,934	31,349
General and administrative	3,777	3,240	11,930	10,114
Oil and gas marketing expenses	41,148	27,946	108,836	119,337
Oil and gas depreciation, depletion and amortization	58,334	46,821	157,731	124,904
Depreciation and amortization of other assets	3,727	2,164	10,489	5,954
Total Operating Costs	138,743	106,537	380,172	347,591
INCOME FROM OPERATIONS	59,439	132,374	102,159	444,385
OTHER INCOME (EXPENSE):				
Interest and other income	1,806	132	7,343	1,384
Interest expense	(28,316)	(24,104)	(79,966)	(72,977)
Impairment of Seven Seas warrants	(4,770)	—	(4,770)	—
Loss on repurchases of debt	(489)	—	(1,353)	—
Gothic standby credit facility costs	—	—	—	(3,392)
Total Other Income (Expense)	(31,769)	(23,972)	(78,746)	(74,985)
INCOME BEFORE INCOME TAX AND EXTRAORDINARY ITEM	27,670	108,402	23,413	369,400
PROVISION FOR INCOME TAXES:				
Current	—	1,118	—	3,354
Deferred	11,070	42,276	9,366	145,265
Total Provision For Income Taxes	11,070	43,394	9,366	148,619
INCOME BEFORE EXTRAORDINARY ITEM	16,600	65,008	14,047	220,781
EXTRAORDINARY ITEM:				
Loss on early extinguishment of debt, net of applicable income tax	—	—	—	(46,000)
NET INCOME	16,600	65,008	14,047	174,781
PREFERED STOCK DIVIDENDS	(2,526)	—	(7,588)	(728)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 14,074	$ 65,008	$ 6,459	$ 174,053
EARNINGS PER COMMON SHARE — BASIC:				
Income before extraordinary item	$ 0.08	$ 0.40	$ 0.04	$ 1.36
Extraordinary item	—	—	—	(0.28)
Net income	$ 0.08	$ 0.40	$ 0.04	$ 1.08
EARNINGS PER COMMON SHARE — ASSUMING DILUTION:				
Income before extraordinary item	$ 0.08	$ 0.38	$ 0.04	$ 1.29
Extraordinary item	—	—	—	(0.27)
Net income	$ 0.08	$ 0.38	$ 0.04	$ 1.02
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING :				
Basic	166,144	164,440	165,829	161,603
Assuming dilution	171,182	170,384	171,540	170,937

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 14,047	$ 174,781
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	164,365	127,987
Risk management (income) loss	86,995	(94,715)
Extraordinary loss on early extinguishment of debt	—	46,000
Deferred income taxes	9,366	145,265
Write-off of credit facility cost	—	3,392
Amortization of loan costs	3,626	2,871
Equity in losses of equity investees	—	1,331
Loss on repurchase of debt	1,353	—
Impairment of Seven Seas warrants	4,770	—
Other	(223)	272
Cash provided by operating activities before changes in assets and liabilities	284,299	407,184
Changes in assets and liabilities	69,359	33,772
Cash provided by operating activities	353,658	440,956
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of oil and gas properties	(252,756)	(263,746)
Acquisition of unproved properties	(46,808)	(64,556)
Acquisition of oil and gas companies and proved properties, net of cash acquired	(291,366)	(62,205)
Sales of oil and gas properties	1,211	1,432
Sales of non-oil and gas assets	75	734
Additions to other fixed assets	(25,919)	(13,049)
Additions to drilling rig equipment	(3,381)	(15,393)
Additions to long-term investments	(2,408)	(37,206)
Proceeds from sale of RAM Energy notes	4,215	—
Other	(46)	(174)
Cash used in investing activities	(617,183)	(454,163)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving bank credit facility	95,818	372,000
Payments on revolving bank credit facility	(95,818)	(208,000)
Cash received from issuance of senior notes	245,984	786,664
Cash paid to repurchase senior notes	(63,541)	(830,382)
Cash paid for premium on repurchase of senior notes	(1,869)	(75,639)
Financing charges	(3,671)	(12,340)
Cash received from exercise of stock options	2,129	2,929
Cash paid for preferred stock dividend	(7,649)	(1,092)
Cash paid in settlement of make-whole provision related to common stock	—	(3,336)
Other	(74)	(10)
Cash provided by financing activities	171,309	30,794
Effect of changes in exchange rate on cash	—	(545)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(92,216)	17,042
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	117,594	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 25,378	$ 17,042

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	($ in thousands)			
Net income	$ 16,600	$ 65,008	$ 14,047	$ 174,781
Other comprehensive income (loss), net of income tax:				
Foreign currency translation adjustments	—	(2,826)	—	(3,551)
Cumulative effect of accounting change for financial derivatives	—	—	—	(53,580)
Change in fair value of derivative instruments	(3,887)	63,857	(16,859)	159,326
Reclassification of (gain) or loss on settled contracts	(3,274)	(34,786)	(19,044)	(18,774)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	32	(575)	1,342	(1,151)
Other	(49)	—	(49)	—
Comprehensive income (loss)	$ 9,422	$ 90,678	$ (20,563)	$ 257,051

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
September 30, 2002
(Unaudited)

1. Basis of Presentation

The accompanying unaudited consolidated financial statements of Chesapeake Energy Corporation and Subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods have been reflected. The results for the three and nine months ended September 30, 2002 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and nine months ended September 30, 2001 (the "Prior Quarter" and "Prior Period", respectively) and the three and nine months ended September 30, 2002 (the "Current Quarter" and "Current Period", respectively).

2. Hedging Activities and Financial Instruments

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2002, our oil and gas derivative instruments were comprised of swaps, collars, cap-swaps, straddles, strangles and basis protection swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, then no payments are due from either party.
- For cap-swaps, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure.
- For straddles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option at an established fixed price. To the extent that the floating market price differs from the established fixed price, Chesapeake pays the counterparty.
- For strangles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option. If the market price exceeds the fixed price of the call option or falls below the fixed price of the put option, then Chesapeake pays the counterparty. If the market price settles between the fixed price of the call and put option, no payment is due from Chesapeake.
- Basis protection swaps are arrangements that guarantee a price differential of oil and gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

From time to time, we close certain swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap, which does not qualify for hedge accounting under SFAS 133, is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption related to commodity derivatives are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

The estimated fair values of our oil and gas derivative instruments as of September 30, 2002 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2002
	($ in thousands)
Derivative assets (liabilities):	
Fixed-price gas swaps	$ (4,800)
Fixed-price gas collars	843
Fixed-price gas cap-swaps	(18,698)
Gas basis protection swaps	2,246
Gas straddles	(3,235)
Gas strangles	(26,808)
Fixed-price gas counter-swaps	13,771
Fixed-price gas locked swaps	20,634
Fixed-price crude oil swaps	(1,894)
Fixed-price crude oil cap-swaps	(3,062)
Estimated fair value	(21,003)
Estimated fair value, as adjusted for premiums received	$ 10,123(a)

(a) After adjusting for the $31.1 million premium paid to Chesapeake by the counterparty at the inception of the straddle and strangle contracts (which is recorded in cash provided by operating activities on the accompanying consolidated statements of cash flows), the net value of the combined hedging portfolio at September 30, 2002 was $10.1 million.

Based upon the market prices at September 30, 2002, we expect to transfer approximately $6.4 million of the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of September 30, 2002 are expected to mature by December 31, 2004, with the exception of the basis protection swaps which extend to 2009.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows ($ in thousands):

Fair value of contracts outstanding at January 1, 2002	$ 157,309
Change in fair value of contracts during period	(48,559)
Contracts realized or otherwise settled during the period	(84,150)
Fair value of new contracts when entered into during the period	(45,603)
Fair value of contracts outstanding at September 30, 2002	$ (21,003)

Risk management income (loss) related to our oil and gas derivatives is comprised of the following ($ in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Risk management income (loss):				
Change in fair value of derivatives not qualifying for hedge accounting	$ 8,056	$ 37,742	$ (34,474)	$ 102,793
Reclassification of gain on settled contracts	(16,764)	(6,440)	(52,471)	(9,996)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(54)	958	(2,236)	1,918
Total	$ (8,762)	$ 32,260	$ (89,181)	$ 94,715

Interest Rate Hedging

We also utilize hedging strategies to manage interest rate exposure. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

In March 2002, we entered into an interest rate swap to convert a portion of our fixed rate debt to floating rate debt. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2002 – March 2004	$200,000,000	7.875%	U.S. six-month LIBOR in arrears plus 298.25 basis points

At the inception of the interest rate swap agreement, a portion of the interest rate swap was entered into to convert $129.0 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge under which the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. During the Current Quarter and Current Period, $21.3 million and $63.5 million face value, respectively, of the 7.875% senior notes were purchased and subsequently retired. In connection with the repurchase of the 7.875% senior notes, interest rate swap hedging gains of $0.4 million and $0.9 million were recognized in the Current Quarter and Current Period, respectively, and reduced the loss on repurchases of debt.

In July 2002, we closed the above interest rate swap for a gain of $7.5 million. As of September 30, 2002, the remaining balance to be amortized as a reduction to interest expense was $4.1 million. During the Current Period, $2.5 million was recognized as a reduction to interest expense.

In June 2002, we entered into an additional interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
July 2002 – July 2004	$100,000,000	4.000%	U.S. six-month LIBOR in arrears

In July 2002, we closed this interest rate swap for a gain of $1.1 million. During the Current Period, $0.1 million was recognized as a reduction to interest expense.

In April 2002, we entered into a swaption agreement in order to monetize the embedded call option in the remaining $142.7 million of our 8.5% senior notes. We received $7.8 million from the counterparty at the time we entered into this agreement. The terms of the swaption are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004 – March 2012	$142,665,000	8.500%	U.S. six-month LIBOR plus 75 basis points

Under the terms of the swaption agreement, the counterparty will have the option to initiate an interest rate swap on March 11, 2004 pursuant to the terms shown above. If the counterparty chooses to initiate the interest rate swap, the payments under the swap will coincide with the semi-annual interest payments on our 8.5% senior notes which are paid on September 15 and March 15 of each year. On each payment date, if the fixed rate exceeds the floating rate, we will pay the counterparty, and if the floating rate exceeds the fixed rate, the counterparty will pay us accordingly. If the counterparty does not choose to initiate the interest rate swap, the swaption agreement will expire and no future obligations will exist for either party.

Under SFAS 133, a fair value hedge relationship exists between the embedded call option in the debt and the swaption agreement. Accordingly, the mark-to-market value of the swaption is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to the debt's carrying value. Any change in the fair value of the swaption resulting from ineffectiveness is recorded currently in the consolidated statements of operations as risk management income (loss).

We have recorded a decrease in the carrying value of the debt of $20.3 million during the Current Period related to the swaption as of September 30, 2002. Of this amount, $21.4 million represents a decline in the fair value of the swaption, offset by a loss of $1.1 million from estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 5 for the adjustments made to the carrying value of the debt at September 30, 2002. Results of the swaption will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

Risk management income related to our fair value hedges is comprised of the following ($ in thousands):

	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2002
Risk management income:		
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 2,292	$ 4,593
Reclassification of gains on settled contracts to interest expense	(576)	(1,307)
Ineffective portion of derivatives qualifying for fair value hedge accounting	—	(1,100)
Total	$ 1,716	$ 2,186

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair value amounts by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term (including current maturities), fixed-rate debt using primarily quoted market prices. Excluding the impact of our fair value hedges, our carrying amount for such debt at December 31, 2001 and September 30, 2002 was $1,330.1 million and $1,512.7 million, respectively, compared to approximate fair values of $1,343.0 and $1,529.4 million, respectively. The carrying amount for our 6.75% convertible preferred stock at September 30, 2002 was $149.9 million, compared to the approximate fair value of $156.5 million.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and cash equivalents, and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas and interest rate volatility. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. The concentration of these assets in the oil and gas industry has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

3. Contingencies and Commitments

West Panhandle Field Cessation Cases. One of our subsidiaries, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. have been defendants in 16 lawsuits filed between June 1997 and December 2001 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which we acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees. The plaintiffs in these cases have claimed the leases terminated upon the cessation of production for various periods, primarily during the 1960s. In addition, the plaintiffs have sought to recover conversion damages, exemplary damages, attorneys' fees and interest. The defendants have asserted that any cessation of production was excused and have pled affirmative defenses of limitations, waiver, temporary estoppel, laches and title by adverse possession. Four of the 16 cases have been tried, and there have been appellate decisions in three of them.

In January 2001, we settled the claims of the principal plaintiffs in eight cases tried or pending in the District Court of Moore County, Texas, 69th Judicial District. The settlement was not material to our financial condition or results of operations. In December 2001, the Texas Supreme Court accepted for review petitions we filed with respect to the claims of the non-settling plaintiffs in two of the cases covered by the settlement. The Court heard oral arguments in March 2002 and has not yet issued a decision.

There are eight other related West Panhandle cessation cases which are pending, three in the District Court of Moore County, Texas, 69th Judicial District, two in the District Court of Carson County, Texas, 100th Judicial District, and three in the U.S. District Court, Northern District of Texas, Amarillo Division. In one of the Moore County cases, CP and the other defendants have appealed a January 2000 judgment notwithstanding verdict in favor of plaintiffs. In addition to quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs, the court awarded actual damages against CP in the amount of $716,400 and exemplary damages in the amount of $25,000. The court further awarded, jointly and severally from all defendants, $160,000 in attorneys' fees and interest and court costs. On March 28, 2001, the Amarillo Court of Appeals reversed and rendered judgment in favor of CP and the other defendants, finding that the subject leases had been revived as a matter of law, making all other issues moot. Plaintiffs have filed petitions requesting that the Texas Supreme Court accept the case for review. In another of the Moore County, Texas cases, in June 1999, the court granted plaintiffs' motion for summary judgment in part, finding that the lease had terminated due to the cessation of production, subject to the defendants' affirmative defenses. In February 2001, the court granted plaintiffs' motion for summary judgment on defendants' affirmative defenses but reversed its ruling that the lease had terminated as a matter of law. In one of the U.S. District Court cases, after a trial in May 1999, the jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches and revivor. Plaintiffs have moved for a new trial. There are motions pending in two other cases, and the remaining three cases are in the pleading stage.

We previously established an accrued liability we believe will be sufficient to cover the estimated costs of litigation for each of the pending cases. Because of the inconsistent verdicts reached by the juries in the four cases tried to date and because the amount of damages sought is not specified in all of the pending cases, the outcome of any future trials and the amount of damages that might ultimately be awarded could differ from management's estimates. CP and the other defendants are vigorously defending against the plaintiffs' claims.

Royalty Owner Litigation. Recently royalty owners have commenced litigation against a number of companies in the oil and gas production business claiming that amounts paid for production attributable to the royalty owners' interest violated the terms of the applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the applicable leases and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. In the course of our oil and gas marketing activities, a portion of the foregoing litigation has been commenced as class action suits including five class action suits filed against Chesapeake and others. No class has been certified in any of the cases in which Chesapeake is a named defendant. We believe the claims asserted do not represent valid claims or, if valid, are not material. As new cases are decided and the law in this area continues to develop, our liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor the court decisions to ensure that our operations and practices minimize any exposure and to recognize any charges that may be appropriate when we can reasonably estimate a liability.

Chesapeake is currently involved in various other routine disputes incidental to its business operations. Management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position or results of operations of Chesapeake.

Due to the nature of the oil and gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake is not aware of any potential material environmental issues or claims.

4. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of “basic” and “diluted” earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS No. 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

- For the Prior Quarter, the Current Quarter, the Prior Period and the Current Period, outstanding warrants to purchase 1.1 million shares of common stock at a weighted average exercise price of $12.61 were antidilutive because the exercise prices of the warrants were greater than the average price of the common stock.

- For the Prior Quarter, the Current Quarter, the Prior Period and the Current Period, outstanding options to purchase 3.8 million, 7.8 million, 0.3 million and 0.5 million shares of common stock at a weighted average exercise price of $6.97, $6.56, $17.25 and $12.77, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.

- Diluted shares in the Current Quarter and Current Period do not include the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares) and the Current Period does not include the common stock equivalent of preferred stock outstanding prior to conversion of 7,611 shares, as the effects were antidilutive.

A reconciliation for the periods presented is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Three Months Ended September 30, 2002:			
Basic EPS			
Income available to common shareholders	$ 14,074	166,144	$ 0.08
Effect of Dilutive Securities			
Employee stock options	—	5,031	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 14,074	171,182	$ 0.08
For the Three Months Ended September 30, 2001:			
Basic EPS			
Income available to common shareholders	$ 65,008	164,440	$ 0.40
Effect of Dilutive Securities			
Employee stock options	—	5,937	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 65,008	170,384	$ 0.38
For the Nine Months Ended September 30, 2002:			
Basic EPS			
Income available to common shareholders	$ 6,459	165,829	$ 0.04
Effect of Dilutive Securities			
Employee stock options	—	5,704	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 6,459	171,540	$ 0.04
For the Nine Months Ended September 30, 2001:			
Basic EPS			
Income available to common shareholders	$ 174,053	161,603	$ 1.08
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:			
Common shares issued	—	1,957	
Preferred stock dividends	728	—	
Employee stock options	—	7,370	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 174,781	170,937	$ 1.02

5. Senior Notes and Revolving Credit Facility

At September 30, 2002, our long-term debt consisted of the following ($ in thousands):

7.875% senior notes, due 2004	$ 86,459
8.375% senior notes, due 2008	250,000
8.125% senior notes, due 2011	800,000
8.5% senior notes, due 2012	142,665
9.0% senior notes, due 2012	250,000
Revolving bank credit facility	—
Discount on senior notes	(16,439)
Discount for interest rate swaps and swaption	(18,505)
Total	$1,494,180

During the Current Period, we purchased and subsequently retired $63.5 million of the 7.875% senior notes for total consideration of $66.3 million, including $0.9 million of accrued interest and $1.9 million of redemption premium. Subsequent to September 30, 2002, we purchased $25.6 million of the 7.875% senior notes for total consideration of $26.8 million, including $0.2 million in accrued interest and $1.0 million in redemption premium.

In August 2002, we issued $250 million principal amount of 9% senior notes due 2012, which were subsequently exchanged on October 24, 2002 for substantially identical notes registered under the Securities Act of 1933.

On September 30, 2002, we had a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of September 30, 2002, we had no outstanding borrowings under this facility and were using $25.5 million of the facility to secure various letters of credit. In November 2002, we increased the credit facility to $250 million (with a committed borrowing base of $225 million). We expect to increase the borrowing base to $250 million and to extend the term of the credit facility to June 2005 during the fourth quarter of 2002. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically.

The credit facility contains various covenants and restrictive provisions which restrict our ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans, purchase certain of our senior notes, create liens, and make acquisitions. The credit facility requires us to maintain a current ratio of at least 1 to 1 (as defined in the credit facility) and a fixed charge coverage ratio of at least 2.5 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. If such an acceleration involved principal in excess of $10.0 million, the acceleration would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility also has cross default provisions that apply to other indebtedness we may have with an outstanding principal balance in excess of $5.0 million.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. The senior note indentures contain covenants limiting us and our guarantor subsidiaries with respect to asset sales; restricted payments; the incurrence of additional indebtedness and the issuance of preferred stock; liens; sale and leaseback transactions; lines of business; dividend and other payment restrictions affecting guarantor subsidiaries; mergers or consolidations; and transactions with affiliates. The senior note indentures also limit our ability to make restricted payments (as defined), including the payment of cash dividends, unless the debt incurrence and other tests are met.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under all our senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by each of our "restricted subsidiaries" (as defined in the respective indentures governing these notes) (collectively, the "guarantor subsidiaries"). Each guarantor subsidiary is a direct or indirect wholly-owned subsidiary.

Set forth below are condensed consolidating financial statements of the guarantor subsidiaries and Chesapeake Energy Marketing, Inc, which is not a guarantor of the senior notes and was a non-guarantor subsidiary for all periods presented. All of our other wholly-owned subsidiaries were guarantor subsidiaries during all periods presented.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF SEPTEMBER 30, 2002
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (31,480)	$ 19,555	$ 37,434	$ —	$ 25,509
Accounts receivable	94,452	51,930	6,168	(32,453)	120,097
Short-term derivative accounts receivable	16,576	—	—	—	16,576
Short-term derivative instruments	843	—	—	—	843
Inventory and other	12,288	531	5	—	12,824
Total Current Assets	92,679	72,016	43,607	(32,453)	175,849
PROPERTY AND EQUIPMENT:					
Oil and gas properties	4,210,692	—	—	—	4,210,692
Unevaluated leasehold	68,995	—	—	—	68,995
Other property and equipment	60,945	28,803	53,156	—	142,904
Less: accumulated depreciation, depletion and amortization	(2,081,287)	(19,696)	(3,895)	—	(2,104,878)
Net Property and Equipment	2,259,345	9,107	49,261	—	2,317,713
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	333,080	(333,080)	—
Long-term derivative receivable	4,058	—	—	—	4,058
Deferred income tax asset	(118,144)	(1,928)	129,789	—	9,717
Long-term investments	—	—	20,734	—	20,734
Other assets	3,628	117	12,850	(33)	16,562
Total Other Assets	(110,458)	(1,811)	496,453	(333,113)	51,071
TOTAL ASSETS	$ 2,241,566	$ 79,312	$ 589,321	$ (365,566)	$ 2,544,633
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ —	$ —	$ —	$ —	$ —
Accounts payable	100,515	51,441	—	(32,453)	119,503
Accrued interest	429	—	44,610	—	45,039
Accrued liabilities	46,558	3,133	9,766	6	59,463
Short-term derivative instruments	22,348	—	—	—	22,348
Total Current Liabilities	169,850	54,574	54,376	(32,447)	246,353
LONG-TERM DEBT	—	—	1,494,180	—	1,494,180
REVENUES AND ROYALTIES DUE OTHERS	14,191	—	—	—	14,191
LONG-TERM DERIVATIVE INSTRUMENTS	20,132	—	29,226	—	49,358
OTHER LIABILITIES	5,764	—	—	—	5,764
INTERCOMPANY PAYABLES	1,724,481	(1,194)	(1,723,248)	(39)	—
STOCKHOLDERS' EQUITY:					
Common Stock	66	1	1,700	(57)	1,710
Other	307,082	25,931	733,087	(333,023)	733,077
Total Stockholders' Equity	307,148	25,932	734,787	(333,080)	734,787
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,241,566	$ 79,312	$ 589,321	$ (365,566)	$ 2,544,633

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2001
($ in thousands)

	Guarantor Subsidiary	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (7,905)	$ 19,714	$ 113,151	$ —	$ 124,960
Accounts receivable	78,950	30,380	2,715	(18,338)	93,707
Short-term derivative receivable	34,543	—	—	—	34,543
Short-term derivative instruments	97,544	—	—	—	97,544
Inventory and other	10,208	421	—	—	10,629
Total Current Assets	213,340	50,515	115,866	(18,338)	361,383
PROPERTY AND EQUIPMENT:					
Oil and gas properties	3,546,163	—	—	—	3,546,163
Unevaluated leasehold	66,205	—	—	—	66,205
Other property and equipment	53,681	23,537	38,476	—	115,694
Less: accumulated depreciation, depletion and amortization	(1,920,613)	(18,668)	(3,200)	—	(1,942,481)
Net Property and Equipment	1,745,436	4,869	35,276	—	1,785,581
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	(21,054)	21,054	—
Long-term derivative receivable	18,852	—	—	—	18,852
Deferred income tax asset	(218,596)	(1,376)	287,753	—	67,781
Long-term derivative instruments	6,370	—	—	—	6,370
Long-term investments	—	—	29,849	—	29,849
Other assets	5,589	334	11,050	(21)	16,952
Total Other Assets	(187,785)	(1,042)	307,598	21,033	139,804
TOTAL ASSETS	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 602	$ —	$ —	$ —	$ 602
Accounts payable	92,203	35,600	—	(18,338)	109,465
Accrued interest	—	—	26,316	—	26,316
Accrued liabilities	35,764	1,155	22	57	36,998
Total Current Liabilities	128,569	36,755	26,338	(18,281)	173,381
LONG-TERM DEBT	—	—	1,329,453	—	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	12,696	—	—	—	12,696
OTHER LIABILITIES	3,831	—	—	—	3,831
INTERCOMPANY PAYABLES	1,664,517	19	(1,664,458)	(78)	—
STOCKHOLDERS' EQUITY:					
Common Stock	66	1	1,686	(57)	1,696
Other	(38,688)	17,567	765,721	21,111	765,711
Total Stockholders' Equity	(38,622)	17,568	767,407	21,054	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2002:					
REVENUES:					
Oil and gas sales	$ 163,012	$ —	$ —	$ —	$ 163,012
Risk management income (loss)	(8,764)	—	1,718	—	(7,046)
Oil and gas marketing sales	—	134,510	—	(92,294)	42,216
Total Revenues	154,248	134,510	1,718	(92,294)	198,182
OPERATING COSTS:					
Production expenses and taxes	31,757	—	—	—	31,757
General and administrative	3,301	471	5	—	3,777
Oil and gas marketing expenses	—	133,442	—	(92,294)	41,148
Oil and gas depreciation, depletion and amortization	58,334	—	—	—	58,334
Other depreciation and amortization	2,668	487	572	—	3,727
Total Operating Costs	96,060	134,400	577	(92,294)	138,743
INCOME FROM OPERATIONS	58,188	110	1,141	—	59,439
OTHER INCOME (EXPENSE):					
Interest and other income	275	300	24,532	(28,560)	(3,453)
Interest expense	(27,990)	(2)	(28,884)	28,560	(28,316)
Equity in net earnings of subsidiaries	—	—	18,526	(18,526)	—
Total Other Income (Expense)	(27,715)	298	14,174	(18,526)	(31,769)
INCOME BEFORE INCOME TAXES	30,473	408	15,315	(18,526)	27,670
INCOME TAX EXPENSE	12,191	164	(1,285)	—	11,070
NET INCOME	$ 18,282	$ 244	$ 16,600	$ (18,526)	$ 16,600

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2001:					
REVENUES:					
Oil and gas sales	$ 177,746	$ —	$ —	$ —	$ 177,746
Risk management income	32,260	—	—	—	32,260
Oil and gas marketing sales	—	94,446	—	(65,541)	28,905
Total Revenues	210,006	94,446	—	(65,541)	238,911
OPERATING COSTS:					
Production expenses and taxes	26,366	—	—	—	26,366
General and administrative	2,835	324	81	—	3,240
Oil and gas marketing expenses	—	93,487	—	(65,541)	27,946
Oil and gas depreciation, depletion and amortization	46,821	—	—	—	46,821
Other depreciation and amortization	1,606	20	538	—	2,164
Total Operating Costs	77,628	93,831	619	(65,541)	106,537
INCOME (LOSS) FROM OPERATIONS	132,378	615	(619)	—	132,374
OTHER INCOME (EXPENSE):					
Interest and other income	107	(956)	24,708	(23,727)	132
Interest expense	(25,044)	—	(22,787)	23,727	(24,104)
Equity in net earnings of subsidiaries	—	—	89,918	(89,918)	—
Total Other Income (Expense)	(24,937)	(956)	91,839	(89,918)	(23,972)
INCOME (LOSS) BEFORE INCOME TAXES	107,441	(341)	91,220	(89,918)	108,402
INCOME TAX EXPENSE	43,009	(136)	26,212	(25,691)	43,394
NET INCOME (LOSS)	$ 64,432	$ (205)	$ 65,008	$ (64,227)	$ 65,008

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2002:					
REVENUES:					
Oil and gas sales	$ 456,992	$ —	$ —	$ —	$ 456,992
Risk management income (loss)	(89,182)	—	2,187	—	(86,995)
Oil and gas marketing sales	—	362,939	—	(250,605)	112,334
Total Revenues	367,810	362,939	2,187	(250,605)	482,331
OPERATING COSTS:					
Production expenses and taxes	91,186	—	—	—	91,186
General and administrative	10,296	1,363	271	—	11,930
Oil and gas marketing expenses	—	359,441	—	(250,605)	108,836
Oil and gas depreciation, depletion and amortization	157,731	—	—	—	157,731
Other depreciation and amortization	7,323	1,257	1,909	—	10,489
Total Operating Costs	266,536	362,061	2,180	(250,605)	380,172
INCOME FROM OPERATIONS	101,274	878	7	—	102,159
OTHER INCOME (EXPENSE):					
Interest and other income	1,427	511	82,349	(83,067)	1,220
Interest expense	(80,620)	(10)	(82,403)	83,067	(79,966)
Equity in net earnings of subsidiaries	—	—	14,075	(14,075)	—
Total Other Income (Expense)	(79,193)	501	14,021	(14,075)	(78,746)
INCOME BEFORE INCOME TAXES	22,081	1,379	14,028	(14,075)	23,413
INCOME TAX EXPENSE (BENEFIT)	8,833	552	(19)	—	9,366
NET INCOME	$ 13,248	$ 827	$ 14,047	$ (14,075)	$ 14,047

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2001:					
REVENUES:					
Oil and gas sales	$ 574,190	$ —	$ —	$ —	$ 574,190
Risk management income	94,715	—	—	—	94,715
Oil and gas marketing sales	—	336,959	—	(213,888)	123,071
Total Revenues	668,905	336,959	—	(213,888)	791,976
OPERATING COSTS:					
Production expenses and taxes	87,282	—	—	—	87,282
General and administrative	8,928	933	253	—	10,114
Oil and gas marketing expenses	—	333,225	—	(213,888)	119,337
Oil and gas depreciation, depletion and amortization	124,904	—	—	—	124,904
Other depreciation and amortization	3,955	60	1,939	—	5,954
Total Operating Costs	225,069	334,218	2,192	(213,888)	347,591
INCOME (LOSS) FROM OPERATIONS	443,836	2,741	(2,192)	—	444,385
OTHER INCOME (EXPENSE):					
Interest and other income	1,246	(982)	71,250	(70,130)	1,384
Interest expense	(77,059)	(1)	(66,047)	70,130	(72,977)
Gothic standby credit facility costs	—	—	(3,392)	—	(3,392)
Equity in net earnings of subsidiaries	—	—	297,975	(297,975)	—
Total Other Income (Expense)	(75,813)	(983)	299,786	(297,975)	(74,985)
INCOME BEFORE INCOME TAXES AND EXTRAORDINARY ITEMS	368,023	1,758	297,594	(297,975)	369,400
INCOME TAX EXPENSE	148,067	704	84,984	(85,136)	148,619
NET INCOME BEFORE EXTRAORDINARY ITEMS	219,956	1,054	212,610	(212,839)	220,781
EXTRAORDINARY ITEMS:					
Loss on early extinguishment of debt, net of applicable income tax	(8,171)	—	(37,829)	—	(46,000)
NET INCOME	$ 211,785	$ 1,054	$ 174,781	$ (212,839)	$ 174,781

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2002:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 311,819	$ (1,205)	$ 57,119	$ (14,075)	$ 353,658
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(297,199)	—	(292,520)	—	(589,719)
Proceeds from sale of assets	75	—	—	—	75
Additions to other property, plant and equipment and other	(5,977)	(5,266)	(14,676)	—	(25,919)
Other investments, net	(3,411)	(16)	1,807	—	(1,620)
Cash (used in) provided by investing activities	(306,512)	(5,282)	(305,389)	—	(617,183)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving bank credit facility	95,818	—	—	—	95,818
Payments on revolving bank credit facility	(95,818)	—	—	—	(95,818)
Cash paid for repurchase of senior notes	—	—	(63,541)	—	(63,541)
Cash paid for repurchase premium on senior notes	—	—	(1,869)	—	(1,869)
Cash received on issuance of senior notes	—	—	245,984	—	245,984
Cash dividends paid on preferred stock	—	—	(7,649)	—	(7,649)
Exercise of stock options	—	—	2,129	—	2,129
Financing charges	—	—	(3,671)	—	(3,671)
Other	—	—	(74)	—	(74)
Intercompany advances, net	(25,605)	6,328	5,202	14,075	—
Cash provided by financing activities	(25,605)	6,328	176,511	14,075	171,309
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(20,298)	(159)	(71,759)	—	(92,216)
CASH, BEGINNING OF PERIOD	(11,313)	19,714	109,193	—	117,594
CASH, END OF PERIOD	$ (31,611)	$ 19,555	$ 37,434	$ —	$ 25,378

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2001:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 409,779	$ 12,271	$ 231,745	$(212,839)	$ 440,956
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(389,075)	—	—	—	(389,075)
Proceeds from sale of assets	734	—	—	—	734
Additions to other property and equipment	(19,819)	(250)	(8,373)	—	(28,442)
Other additions	(174)	—	(37,206)	—	(37,380)
Cash (used in) provided by investing activities	(408,334)	(250)	(45,579)	—	(454,163)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving bank credit facility	372,000	—	—	—	372,000
Payments on revolving bank credit facility	(208,000)	—	—	—	(208,000)
Cash paid for financing costs related to debt	—	—	—	—	—
Cash dividends paid on preferred stock	—	—	(1,092)	—	(1,092)
Cash paid for repurchase of senior notes	—	—	(830,382)	—	(830,382)
Cash paid for repurchase premium on senior notes	—	—	(75,639)	—	(75,639)
Financing charges	(5,672)	—	(6,668)	—	(12,340)
Cash received on issuance of senior notes	—	—	786,664	—	786,664
Exercise of stock options	—	—	2,929	—	2,929
Cash paid in settlement of make-whole provision related to common stock	—	—	(3,336)	—	(3,336)
Other	—	—	(10)	—	(10)
Intercompany advances, net	8,686	(19,388)	(202,137)	212,839	—
Cash (used in) provided by financing activities	167,014	(19,388)	(329,671)	212,839	30,794
Effect of exchange rate changes on cash	(545)	—	—	—	(545)
NET INCREASE (DECREASE) IN CASH	167,914	(7,367)	(143,505)	—	17,042
CASH, BEGINNING OF PERIOD	(19,868)	7,200	12,668	—	—
CASH, END OF PERIOD	$ 148,046	$ (167)	$(130,837)	$ —	$ 17,042

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2002:					
Net income	$ 18,282	$ 244	$ 16,600	$ (18,526)	$ 16,600
Other comprehensive income (loss), net of income tax:					
Change in fair value of derivative instruments	(3,887)	—	—	—	(3,887)
Reclassification of (gain) or loss on settled contracts	(3,274)	—	—	—	(3,274)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	32	—	—	—	32
Other	—	—	(49)	—	(49)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(7,129)	7,129	—
Comprehensive income	$ 11,153	$ 244	$ 9,422	$ (11,397)	$ 9,422

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2001:					
Net income (loss)	$ 64,432	$ (205)	$ 39,317	$ (38,536)	$ 65,008
Other comprehensive income, net of income tax:					
Foreign currency translation	(2,826)	—	—	—	(2,826)
Change in fair value of derivative instruments	63,857	—	—	—	63,857
Reclassification of (gain) or loss on settled contracts	(34,786)	—	—	—	(34,786)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(575)	—	—	—	(575)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	25,670	(25,670)	—
Comprehensive income (loss)	$ 90,102	$ (205)	$ 64,987	$ (64,206)	$ 90,678

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2002:					
Net income	$ 13,248	$ 827	$ 14,047	$ (14,075)	$ 14,047
Other comprehensive income (loss), net of income tax:					
Change in fair value of derivative instruments	(16,859)	—	—	—	(16,859)
Reclassification of (gain) or loss on settled contracts	(19,044)	—	—	—	(19,044)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	1,342	—	—	—	1,342
Other	—	—	(49)	—	(49)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(34,561)	34,561	—
Comprehensive income (loss)	$ (21,313)	$ 827	$ (20,563)	$ 20,486	$ (20,563)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2001:					
Net income	$ 211,785	$ 1,054	$ 89,645	$ (127,703)	$ 174,781
Other comprehensive income (loss), net of income tax:					
Foreign currency translation	(3,551)	—	—	—	(3,551)
Cumulative effect of accounting change for financial derivatives	(53,580)	—	—	—	(53,580)
Change in fair value of derivative instruments	159,326	—	—	—	159,326
Reclassification of (gain) or loss on settled contracts	(18,774)	—	—	—	(18,774)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(1,151)	—	—	—	(1,151)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	82,270	(82,270)	—
Comprehensive income	$ 294,055	$ 1,054	$ 171,915	$ (209,973)	$ 257,051

6. Segment Information

Chesapeake has two reportable segments under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*. One segment is related to our exploration and production activities, and the other segment is related to oil and gas marketing activities. The reportable segment information can be derived from the condensed consolidating financial statements included in Note 5. The separate results and financial condition of Chesapeake Energy Marketing, Inc., our wholly owned subsidiary which conducts all our marketing activities, are reflected in the column captioned “Non-Guarantor Subsidiary.”

7. Recent Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards Nos. 141 and 142. SFAS No. 141, *Business Combinations*, requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS No. 142, *Goodwill and Other Intangible Assets*, changes the accounting for goodwill from an amortization method to an impairment-only approach and was effective in January 2002. We have adopted these new standards, which have not had a significant effect on our results of operations or our financial position.

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 is effective for fiscal years beginning after June 15, 2002 and establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-term assets (mainly plugging and abandonment costs for our depleted wells) in the period in which the liability is incurred (at the time the wells are drilled). We are currently evaluating our oil and natural gas properties to determine the impact of the adoption of SFAS 143 on our financial position and results of operations.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* SFAS 144 was effective January 1, 2002. This statement supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of,* and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. Our adoption of SFAS 144 did not affect our financial position or results of operations.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. We have early adopted this standard and it did not have a significant effect on our results of operations or our financial position.

In July 2002, the FASB issued SFAS No. 146, *Accounting For Costs Associated with Exit or Disposal Activities*. SFAS No. 146 is effective for exit or disposal activities initiated after December 31, 2002. We have no such activities, thus we do not believe the impact of the adoption of SFAS No. 146 will be material.

8. Subsequent Event

On November 6, 2002, Chesapeake priced a private offering of \$50 million principal amount of 9.0% senior notes due 2012. The net proceeds are expected to be approximately \$51.3 million. The 9.0% senior notes will be issued as additional securities under the August 12, 2002 indenture pursuant to which our outstanding 9.0% senior notes were issued. Closing of the offering is expected to occur on November 13, 2002, and is subject to satisfaction of customary closing conditions. The net proceeds from this offering are expected to be used for repurchase of amounts currently outstanding under our 7.875% senior notes and under our revolving bank credit facility. The 9.0% senior notes to be issued will not be registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

PART I. FINANCIAL INFORMATION

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

Overview

The following table sets forth certain information regarding the production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Net Production:				
Oil (mbbl)	872	705	2,525	2,073
Gas (mmcf)	41,429	36,549	116,826	107,634
Gas equivalent (mmcfe)	46,661	40,779	131,976	120,072
Oil and Gas Sales ($ in thousands):				
Oil	$ 22,384	$ 19,299	$ 64,193	$ 58,096
Gas	140,628	158,447	392,799	516,094
Total oil and gas sales	$ 163,012	$ 177,746	$ 456,992	$ 574,190
Average Sales Price:				
Oil ($ per bbl)	$ 25.67	$ 27.37	$ 25.42	$ 28.03
Gas ($ per mcf)	$ 3.39	$ 4.34	$ 3.36	$ 4.79
Gas equivalent ($ per mcfe)	$ 3.49	$ 4.36	$ 3.46	$ 4.78
Expenses ($ per mcfe):				
Production expenses	$ 0.53	$ 0.47	$ 0.54	$ 0.47
Production taxes	$ 0.15	$ 0.17	$ 0.15	$ 0.26
General and administrative	$ 0.08	$ 0.08	$ 0.09	$ 0.08
Depreciation, depletion and amortization	$ 1.25	$ 1.15	$ 1.20	$ 1.04
Net Wells Drilled	79	54	204	208
Net Wells at End of Period	4,102	3,458	4,102	3,458

Results of Operations — Three Months Ended September 30, 2002 ("Current Quarter") vs. September 30, 2001 ("Prior Quarter")

General. For the Current Quarter, Chesapeake had net income available to common shareholders of $14.1 million, or $0.08 per diluted common share, on total revenues of $198.2 million. This compares to net income available to common shareholders of $65.0 million, or $0.38 per diluted common share, on total revenues of $238.9 million during the Prior Quarter. The Current Quarter's results included, on a pre-tax basis, a non-cash $7.0 million risk management loss, a non-cash impairment of $4.8 million representing 100% of the cost we allocated to common stock warrants of Seven Seas Petroleum Inc. and a $0.5 million loss from repurchases of debt. The Prior Quarter's results included, on a pre-tax basis, non-cash risk management income of $32.3 million.

Oil and Gas Sales. During the Current Quarter, oil and gas sales decreased 8% to $163.0 million from $177.7 million in the Prior Quarter. For the Current Quarter, we produced 46.7 billion cubic feet equivalent (bcfe), consisting of 0.9 million barrels of oil (mmbbl) and 41.4 billion cubic feet of gas (bcf), compared to 0.7 mmbbl and 36.5 bcf, or 40.8 bcfe, in the Prior Quarter. The production increase is the result of successful drilling results and production from various acquisitions completed during the Current Quarter partially offset by the sale of our Canadian reserves effective October 1, 2001. Average oil prices realized were $25.67 per bbl in the Current Quarter compared to $27.37 per bbl in the Prior Quarter, a decrease of 6%. Average gas prices realized were $3.39 per thousand cubic feet in the Current Quarter compared to $4.34 per mcf in the Prior Quarter, a decrease of 22%.

For the Current Quarter, we realized an average price of $3.49 per mcfe, compared to $4.36 per mcfe in the Prior Quarter, including in each case the effects of hedging. Our hedging activities resulted in increased oil and gas revenues of $22.2 million, or $0.47 per mcfe, in the Current Quarter, compared to an increase in oil and gas revenues of $64.4 million, or $1.58 per mcfe, in the Prior Quarter.

The following table shows our production by region for the Prior Quarter and the Current Quarter:

	For the Three Months Ended September 30,			
	2002		2001	
Operating Areas	(Mmcfe)	Percent	(Mmcfe)	Percent
Mid-Continent	39,024	84%	29,159	72%
Gulf Coast	5,074	11	6,279	15
Permian Basin	1,719	3	3,276	8
Other areas	844	2	1,155	3
Canada	—	—	910	2
Total	46,661	100%	40,779	100%

Gas production represented approximately 89% of our total production volume on an equivalent basis in the Current Quarter, compared to 90% in the Prior Quarter.

Risk Management Income (Loss). Chesapeake recognized a $7.0 million non-cash risk management loss in the Current Quarter, compared to a $32.3 million non-cash gain in the Prior Quarter. The risk management loss for the Current Quarter consisted of a $10.3 million non-cash gain related to changes in fair value of derivatives not designated as cash flow hedges and $17.3 million of reclassifications of gains on the settlement of such contracts. Risk management income in the Prior Quarter included a $37.7 million non-cash gain attributable to the change in fair value of derivatives not designated as cash flow hedges, $6.4 million of reclassifications of gains on the settlement of such contracts, and a non-cash gain of $1.0 million associated with the ineffective portion of our cash flow hedges.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. There was also a portion of our interest rate swaps that did not qualify as a fair value hedge. Therefore, changes in fair value of these instruments that occur prior to their maturity, together with any change in fair value of hedges resulting from ineffectiveness, are reported in the statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive cash flow or fair value hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and are included in oil and gas sales and interest expense, as applicable, over the respective contract terms. Detailed information about our oil and gas hedging positions appears in Item 3 – Quantitative and Qualitative Disclosures About Market Risk.

Oil and Gas Marketing Sales. We generated $42.2 million in oil and gas marketing sales for third parties in the Current Quarter, with corresponding oil and gas marketing expenses of $41.1 million, for a net margin of $1.1 million. This compares to sales of $28.9 million, expenses of $27.9 million, and a net margin of $1.0 million in the Prior Quarter. The increase in marketing sales and cost of sales was due primarily to an increase in oil and gas sales volumes and sales prices in the Current Quarter compared to the Prior Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, increased to $25.0 million in the Current Quarter, a $5.7 million increase from the $19.3 million of production expenses incurred in the Prior Quarter. On a unit of production basis, production expenses were $0.53 and $0.47 per mcfe in the Current and Prior Quarters, respectively. The increase in costs on a per unit basis in the Current Quarter is due primarily to increased field service costs, higher production costs associated with properties acquired in 2001 and 2002 and an increase in ad valorem taxes and insurance costs. We expect that lease operating expenses per mcfe for the remainder of 2002 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $6.8 million and $7.1 million in the Current and Prior Quarters, respectively. On a per unit basis, production taxes were $0.15 per mcfe in the Current Quarter compared to $0.17 per mcfe in the Prior Quarter. The decrease in the Current Quarter was the result of the reinstatement of statutory exemptions on certain wells in Oklahoma, partially offset by an increase in oil and gas prices. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes for the remainder of 2002 to be approximately 6% - 7% of oil and gas sales revenues excluding any impact from hedging.

General and Administrative. General and administrative expenses, which are net of capitalized internal costs, were $3.8 million in the Current Quarter compared to $3.2 million in the Prior Quarter. The increase in the Current Quarter is the result of Chesapeake's continued growth.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $2.5 million and $2.1 million of internal costs in the Current Quarter and Prior Quarter, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for the remainder of 2002 will be between $0.10 and $0.11 per mcfe, which is approximately the same level as 2001 and the Current Quarter.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Quarter was $58.3 million, compared to $46.8 million in the Prior Quarter. The DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, increased from $1.15 in the Prior Quarter to $1.25 per mcfe in the Current Quarter. We expect the DD&A rate for the remainder of 2002 to be between $1.25 and $1.30 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $3.7 million in the Current Quarter, compared to $2.2 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation recorded on recently acquired fixed assets. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from three to seven years. We expect depreciation and amortization of other assets to average between $0.08 and $0.10 per mcfe for the remainder of 2002 which approximates the current rate.

Interest and Other Income. Interest and other income for the Current Quarter was $1.8 million compared to $0.1 million in the Prior Quarter. The increase was primarily the result of the recognition of a $1.0 million loss in the Prior Quarter which represented our share of the net loss of RAM Energy, Inc., and interest income recorded in the Current Quarter on our investment in senior secured notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $28.3 million in the Current Quarter from $24.1 million in the Prior Quarter. The increase in the Current Quarter was due primarily to a $327 million increase in average long-term borrowings in the Current Quarter compared to the Prior Quarter, partially offset by income of $1.1 million earned on our interest rate swaps during the Current Quarter. In addition to the interest expense reported, we capitalized $1.3 million of interest during the Current Quarter, compared to $1.2 million capitalized in the Prior Quarter, on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate of our outstanding borrowings. We anticipate that capitalized interest for the remainder of 2002 will be between $1.0 million and $1.5 million.

Other. Chesapeake recorded a non-cash impairment of $4.8 million representing 100% of the cost allocated to our Seven Seas common stock warrants and also recorded a $0.5 million loss from the repurchase of debt.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $11.1 million in the Current Quarter, compared to income tax expense of $43.4 million in the Prior Quarter. We anticipate that all 2002 income tax expense will be deferred.

Results of Operations — Nine Months Ended September 30, 2002 ("Current Period") vs. September 30, 2001 ("Prior Period")

General. For the Current Period, Chesapeake had net income available to common shareholders of $6.5 million, or $0.04 per diluted common share, on total revenues of $482.3 million. This compares to net income available to common shareholders of $174.1 million, or $1.02 per diluted common share, on total revenues of $792.0 million during the Prior Period. The Current Period's net income included, on a pre-tax basis, a non-cash $87.0 million risk management loss, while the Prior Period's results included, on a pre-tax basis, non-cash risk management income of $94.7 million.

Oil and Gas Sales. During the Current Period, oil and gas sales decreased 20% to $457.0 million from $574.2 million in the Prior Period. For the Current Period, we produced 132.0 bcfe, consisting of 2.5 mmbbl and 116.8 bcf of gas, compared to 2.1 mmbbl and 107.6 bcf, or 120.1 bcfe, in the Prior Period. The production increase is primarily the result of successful drilling results complemented with production from various acquisitions which occurred in late 2001 and 2002 partially offset by the sale of our Canadian reserves effective October 1, 2001. Average oil prices realized were $25.42 per bbl in the Current Period compared to $28.03 per bbl in the Prior Period, a decrease of 9%. Average gas prices realized were $3.36 per mcf in the Current Period compared to $4.79 per mcf in the Prior Period, a decrease of 30%.

For the Current Period, we realized an average price of $3.46 per mcfe, compared to $4.78 per mcfe in the Prior Period, including in each case the effects of hedging. Our hedging activities resulted in increased oil and gas revenues of $84.1 million, or $0.64 per mcfe, in the Current Period, compared to increases in oil and gas revenues of $41.1 million, or $0.34 per mcfe, in the Prior Period.

The following table shows our production by region for the Prior Period and the Current Period:

	For the Nine Months Ended September 30,			
	2002		2001	
Operating Areas	**(Mmcfe)**	**Percent**	**(Mmcfe)**	**Percent**
Mid-Continent	105,996	80%	83,553	70%
Gulf Coast	18,059	14	21,205	18
Permian Basin	5,524	4	9,074	7
Other areas	2,397	2	3,827	3
Canada	—	—	2,413	2
Total	131,976	100%	120,072	100%

Gas production represented approximately 89% of our total production volume on an equivalent basis in the Current Period, compared to 90% in the Prior Period.

Risk Management Income (Loss). Chesapeake recognized an $87.0 million non-cash risk management loss in the Current Period, compared to a $94.7 million non-cash gain in the Prior Period. The risk management loss for the Current Period consisted of a $29.9 million non-cash loss related to changes in fair value of derivatives not designated as cash flow hedges, $53.8 million of reclassifications of gain on the settlement of such contracts, a $2.2 million non-cash loss associated with the ineffective portion of derivatives qualifying for cash flow hedge accounting, and a $1.1 million non-cash loss associated with the ineffective portion of our swaption. Risk management income for the Prior Period included a $102.8 million non-cash gain attributable to the change in fair value of derivatives not designated as cash flow hedges, $10.0 million of reclassifications of gain on the settlement of such contracts, and a non-cash gain of $1.9 million associated with the ineffective portion of our cash flow hedges.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. There was also a portion of our interest rate swaps that did not qualify as a fair value hedge. Therefore, changes in fair value of these instruments that occur prior to their maturity, together with any change in fair value of hedges resulting from ineffectiveness, are reported in the statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive cash flow or fair value hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and are included in oil and gas sales and interest expense, as applicable, over the respective contract terms. Detailed information about our oil and gas hedging positions appears in Item 3 – Quantitative and Qualitative Disclosures About Market Risk.

Oil and Gas Marketing Sales. We generated $112.3 million in oil and gas marketing sales for third parties in the Current Period, with corresponding oil and gas marketing expenses of $108.8 million, for a net margin of $3.5 million. This compares to sales of $123.1 million, expenses of $119.3 million, and a net margin of $3.8 million in the Prior Period. The decrease in marketing sales and cost of sales was due primarily to a decrease in oil and gas prices in the Current Period compared to the Prior Period, partially offset by an increase in volumes marketed by Chesapeake Energy Marketing, Inc. in the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, increased to $71.3 million in the Current Period, a $15.4 million increase from the $55.9 million of production expenses incurred in the Prior Period. On a unit of production basis, production expenses were $0.54 and $0.47 per mcfe in the Current and Prior Periods, respectively. The increase in costs on a per unit basis in the Current Period is due primarily to increased field service costs, higher production costs associated with properties acquired in 2001 and 2002 and an increase in ad valorem taxes and insurance costs. We expect that lease operating expenses per mcfe for the remainder of 2002 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $19.9 million and $31.3 million in the Current and Prior Periods, respectively. On a per unit basis, production taxes were $0.15 per mcfe in the Current Period compared to $0.26 per mcfe in the Prior Period. The decrease in the Current Period was the result of decreased prices and the reinstatement of statutory exemptions on certain wells in Oklahoma. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes for the remainder of 2002 to be approximately 6% - 7% of oil and gas sales revenues excluding any impact from hedging.

General and Administrative. General and administrative expenses, which are net of capitalized internal costs, were $11.9 million in the Current Period compared to $10.1 million in the Prior Period. The increase in the Current Period is a result of Chesapeake's continued growth.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $7.8 million and $6.0 million of internal costs in the Current Period and Prior Period, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for the remainder of 2002 will be between $0.10 and $0.11 per mcfe, which is approximately the same level as 2001 and the Current Period.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Period was $157.7 million, compared to $124.9 million in the Prior Period. The DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, increased from $1.04 in the Prior Period to $1.20 per mcfe in the Current Period. We expect the DD&A rate for the remainder of 2002 to be between $1.25 and $1.30 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $10.5 million in the Current Period, compared to $6.0 million in the Prior Period. The increase in the Current Period was primarily the result of higher depreciation recorded on recently acquired fixed assets. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from three to seven years. We expect depreciation and amortization of other assets to average between $0.08 and $0.10 per mcfe for the remainder of 2002 which approximates the current rate.

Interest and Other Income. Interest and other income for the Current Period was $7.3 million compared to $1.4 million in the Prior Period. The increase was primarily the result of additional interest income from significantly higher cash balances held during the Current Period and an increase in interest income recorded on our investment in senior secured notes issued by Seven Seas Petroleum Inc. The Prior Quarter included the recognition of a $1.3 million loss, representing our share of the net loss of RAM Energy, Inc.

Interest Expense. Interest expense increased to $80.0 million in the Current Period from $73.0 million in the Prior Period. The increase in the Current Period was due to a $301 million increase in average long-term borrowings in the Current Period compared to the Prior Period, partially offset by income of $2.7 million earned on our interest rate swaps during the Current Period. In addition to the interest expense reported, we capitalized $3.6 million and $3.3 million of interest during the Current Period and Prior Period, respectively, on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate of our outstanding borrowings. We anticipate that capitalized interest for the remainder of 2002 will be between $1.0 million and $1.5 million.

Gothic Standby Credit Facility Costs. We recognized $3.4 million of costs incurred for a standby credit facility in the Prior Period in connection with our acquisition of Gothic Energy Corporation. We did not use the facility which was obtained and the commitment terminated in February 2001.

Other. Chesapeake recorded a non-cash impairment of $4.8 million representing 100% of the cost allocated to our Seven Seas common stock warrants and also recorded a $0.5 million loss from the repurchase of debt.

Provision (Benefit) for Income Taxes. Chesapeake recorded an income tax expense of $9.4 million in the Current Period, compared to income tax expense of $148.6 million in the Prior Period. Income tax expense for the Prior Period was comprised of $141.5 million related to our domestic operations and $7.1 million related to our Canadian operations which were sold on October 1, 2001. We anticipate that all 2002 income tax expense will be deferred.

Extraordinary Item. The $46.0 million extraordinary loss in the Prior Period includes the payment of aggregate make-whole and redemption premiums related to debt repurchases and redemptions and the write-off of related unamortized debt issue costs and unamortized debt issue premium.

Cash Flows From Operating, Investing, and Financing Activities

Cash Flows from Operating Activities. Cash provided by operating activities decreased 19.8% to $353.7 million during the Current Period compared to $441.0 million during the Prior Period. The decrease was due primarily to lower oil and gas prices realized during the Current Period.

Cash Flows from Investing Activities. Cash used in investing activities increased to $617.2 million during the Current Period from $454.2 million in the Prior Period. During the Current Period, we expended approximately $252.8 million to initiate drilling on 517 (204 net) wells and invested approximately $46.8 million in unproved properties. This compares to $263.7 million to initiate drilling on 409 (208 net) wells and $64.6 million to purchase unproved properties in the Prior Period. During the Current Period, we completed acquisitions of oil and gas companies and properties of $291.4 million and completed $1.2 million of divestitures of oil and gas properties. This compares to cash used in acquisitions of oil and gas companies and properties of $62.2 million and proceeds from divestitures of $1.4 million in the Prior Period. During the Current Period, we had additional investments in drilling rig equipment and other fixed assets of $29.3 million compared to $28.4 million in the Prior Period. The Current Period included additional investments in the common stock of two oil and gas companies totaling $2.4 million and $4.2 million in proceeds from the sale of RAM Energy, Inc. notes.

Cash Flows from Financing Activities. There was $171.3 million of cash provided by financing activities in the Current Period, compared to cash provided by financing activities of $30.8 million in the Prior Period. During the Current Period, we borrowed $95.8 million under our bank credit facility and made repayments under this facility of $95.8 million. The activity in the Current Period includes the repurchase of $63.5 million of our 7.875% senior notes. We received $246.0 million from the issuance of $250 million of 9% senior notes, $2.1 million in cash from the exercise of stock options, $3.7 million was used to pay financing cost, and $7.6 million was used to pay dividends on our 6.75% preferred stock. The activity in the Prior Period included increased borrowings under our credit facility of $164.0 million, $786.7 million received from the issuance of $800.0 million of 8.125% senior notes, $830.4 million used to redeem various senior notes, $12.3 million was used for financing cost, and $2.9 million received from the exercise of stock options.

Liquidity and Capital Resources

Sources of Liquidity

Chesapeake had a working capital deficit of $70.5 million at September 30, 2002, including $25.4 million in cash. On September 30, 2002, we had a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which was increased to $250 million (with a committed borrowing base of $225 million) in November 2002. As of September 30, 2002, we had no outstanding borrowings under the facility and were using $25.5 million of the facility to secure various letters of credit. As of November 5, 2002, borrowings under the credit facility had increased to $62.5 million, largely as a result of borrowings to fund acquisitions and note purchases which occurred subsequent to September 30, 2002.

We believe we will have adequate resources, including operating cash flows, working capital and proceeds from our revolving bank credit facility, to fund our capital expenditure budget for exploration and development activities during the fourth quarter of 2002, which is currently estimated to be $90 to $100 million. Based on our current cash flow assumptions, we expect operating cash flow to be approximately $400 million during 2002. The 2003 budget includes $350 million for exploration and developmental activities and $50 million for acreage and seismic. Our drilling program is largely discretionary and can be adjusted to match changing circumstances.

A significant portion of our liquidity is concentrated in cash and cash equivalents (including restricted cash) and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. The concentration of these assets in the oil and gas industry has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

Our liquidity is not dependent on the use of off-balance sheet financing arrangements, such as the securitization of receivables or obtaining access to assets through special purpose entities. We have not relied on off-balance sheet financing arrangements in the past and we do not intend to rely on such arrangements in the future as a source of liquidity. We do not issue commercial paper.

Contractual Obligations and Commercial Commitments

On September 30, 2002, we had a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which was increased to $250 million (with a committed borrowing base of $225 million) in November 2002. We expect to increase the borrowing base to $250.0 million and to extend the term of the credit facility to June 2005 during the fourth quarter of 2002. As of September 30, 2002, we had no outstanding borrowings under this facility and were using $25.5 million of the facility to secure various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically.

The credit facility contains various covenants and restrictive provisions which restrict our ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans, purchase certain of our senior notes, create liens, and make acquisitions. The credit facility requires us to maintain a current ratio of at least 1 to 1 (as defined in the credit facility) and a fixed charge coverage ratio of at least 2.5 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. If such an acceleration involved principal in excess of $10 million, the acceleration would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility also has cross default provisions that apply to other indebtedness we may have with an outstanding principal balance in excess of $5.0 million.

As of September 30, 2002, senior notes represented $1.5 billion of our long-term debt and consisted of the following: $800.0 million principal amount of 8.125% senior notes due 2011, $250.0 million principal amount of 9.0% senior notes due 2012, $250.0 million principal amount of 8.375% senior notes due 2008, $86.5 million principal amount of 7.875% senior notes due 2004 and $142.7 million principal amount of 8.5% senior notes due 2012. There are no scheduled principal payments required on any of the senior notes until March 2004, when $60.8 million is due, giving effect to the repurchase and retirement of $89.2 million of our 7.875% senior notes to date. Debt ratings for the senior notes are B1 by Moody's Investor Service, B+ by Standard & Poor's Ratings Services and BB- by Fitch Ratings. Debt ratings for our secured bank credit facility are Ba3 by Moody's Investor Service, BB by Standard & Poor's Ratings Services and BB+ by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly owned subsidiaries except Chesapeake Energy Marketing, Inc. guarantee the notes. We can acquire outstanding senior notes at either make-whole or redemption prices set forth in the respective indentures, and from time to time we acquire senior notes through market purchases.

The indentures for the 8.125%, 8.375% and 9% senior notes contain covenants limiting our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not affect our ability to borrow under or expand our secured credit facility. As of September 30, 2002, we estimate that secured commercial bank indebtedness of approximately $381 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., an unrestricted subsidiary.

Some of our commodity price and interest rate risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations under the arrangements exceed certain levels. At September 30, 2002, we posted $24.5 million of collateral with two of our counterparties through letters of credit secured under our bank credit facility. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and the level of volatility in natural gas and oil prices and interest rates.

Investing and Financing Transactions

In the Current Period, we purchased and subsequently retired $63.5 million of our 7.875% senior notes due 2004 for total consideration of $66.3 million, including accrued interest of $0.9 million and $1.9 million of redemption premium. Subsequent to September 30, 2002, we purchased an additional $25.6 million of the 7.875% senior notes for total consideration of $26.8 million, including $0.2 million in accrued interest and $1.0 million in redemption premium.

On June 28, 2002, we acquired Canaan Energy Corporation in a cash merger, adding an estimated 100 bcfe to our proved reserves. The aggregate net cash consideration for the merger was $120 million, including the retirement of Canaan's outstanding indebtedness of approximately $43 million.

In July 2002, we filed a shelf registration statement with the Securities and Exchange Commission that permits us, over time, to sell up to $500 million of debt securities and common stock, in any combination. Net proceeds, terms and pricing of the offerings of securities issued under the shelf registration statement will be determined at the time of the offerings.

In July and August 2002, we completed four separate acquisitions of Mid-Continent oil and gas properties for an aggregate cash purchase price of $165 million. We estimate these acquisitions added approximately 125 bcfe of proved reserves. The acquisitions included privately-held Focus Energy, Inc. and related partnerships, the Mid-Continent assets of publicly-traded EnCana Corporation, the Mid-Continent assets of OGE Energy Corp. and the Anadarko Basin assets of The Williams Company.

In August 2002, we issued $250 million principal amount of 9.0% senior notes due 2012. The net proceeds of this issuance were used to fund the acquisitions we completed in August 2002, to repay bank debt incurred to pay the purchase price of acquisitions earlier in the Current Quarter and to purchase outstanding senior notes.

On September 20, 2002, our board of directors declared a $0.03 per share dividend on the company's common stock which was paid in October 2002. Chesapeake has not paid a dividend on its common stock since 1998. The annualized cost of the common stock dividend will be about $20 million.

In September 2002, we announced our intention to dispose of our Permian Basin assets, preferably in a transaction involving the exchange of oil and gas assets in the Mid-Continent for ours in the Permian Basin. The Permian Basin accounted for approximately 5% of our proved reserves at September 30, 2002 and 2.4 bcfe, or 4%, of our production for the nine months ended September 30, 2002.

On November 6, 2002, Chesapeake priced a private offering of $50 million principal amount of 9.0% senior notes due 2012. The net proceeds are expected to be approximately $51.3 million. The 9.0% senior notes will be issued as additional securities under the August 12, 2002 indenture pursuant to which our outstanding 9.0% senior notes were issued. Closing of the offering is expected to occur on November 13, 2002, and is subject to satisfaction of customary closing conditions. The net proceeds from this offering are expected to be used for repurchase of amounts currently outstanding under our 7.875% senior notes and under our revolving bank credit facility. The 9.0% senior notes to be issued will not be registered under the Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

Critical Accounting Policies

We consider certain accounting policies related to hedging, oil and gas properties, and income taxes to be critical policies. These policies and other significant accounting policies are summarized in our annual report on Form 10-K for the year ended December 31, 2001.

Recently Issued Accounting Standards

See Note 7 of the notes to the consolidated financial statements included in this report for a summary of recently issued accounting standards.

Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and gas reserve estimates, planned capital expenditures, the drilling of oil and gas wells and future acquisitions, expected oil and gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations, expected future expenses and assessments of pending litigation. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1 of our Form 10-K for the year ended December 31, 2001. These factors include:

- the volatility of oil and gas prices,
- our substantial indebtedness,
- the cost and availability of drilling and production services,
- our commodity price risk management activities, including counterparty contract performance risk,
- uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures,
- our ability to replace reserves,
- the availability of capital,
- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- drilling and operating risks,
- our ability to generate future taxable income sufficient to utilize our federal and state income tax net operating loss (NOL) carryforwards before their expiration,
- future ownership changes which could result in additional limitations to our NOLs,
- adverse effects of governmental and environmental regulation,
- losses possible from pending or future litigation,
- the strength and financial resources of our competitors, and
- the loss of officers or key employees.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this and our other reports filed with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2002, our derivative instruments were comprised of swaps, collars, cap-swaps, straddles, strangles and basis protection swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, then no payments are due from either party.
- For cap-swaps, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a “cap” limiting the counterparty’s exposure.
- For straddles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option at an established fixed price. To the extent that the floating market price differs from the established fixed price, Chesapeake pays the counterparty.
- For strangles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option. If the market price exceeds the fixed price of the call option or falls below the fixed price of the put option, then Chesapeake pays the counterparty. If the market price settles between the fixed price of the call and put option, no payment is due from Chesapeake.
- Basis protection swaps are arrangements that guarantee a price differential of oil and gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

From time to time, we close certain swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap, which does not qualify for hedge accounting, is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption related to commodity derivatives are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

As of September 30, 2002, we had the following open oil and gas derivative instruments designed to hedge a portion of our gas production for periods after September 2002:

	Volume	Average Strike Price	Weighted-Average Put Strike Price	Weighted-Average Call Strike Price	Weighted-Average Differential	SFAS 133 Hedge	Premiums Received	Fair Value at September 30, 2002 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
2002	920,000	$ 3.00	$ —	$ —	$ —	Yes	$ —	$ (817)
2003	22,810,000	4.10	—	—	—	Yes	—	(3,983)
Cap-Swaps:								
2002	18,120,000	4.49	3.49	—	—	No	—	7,111
2003	51,100,000	3.60	2.60	—	—	No	—	(25,809)
Collars:								
2002	2,460,000	—	4.00	5.56	—	Yes	—	843
Straddles:								
2002	3,680,000	—	3.25	3.25	—	No	2,613	(3,235)
Strangles:								
2003	14,600,000	—	3.20	3.70	—	No	12,629	(12,235)
2004	14,640,000	—	3.40	3.90	—	No	15,884	(14,573)
Basis Protection Swaps:								
2003	91,250,000	—	—	—	(0.15)	No	—	1,953
2004	91,500,000	—	—	—	(0.15)	No	—	378
2005	98,550,000	—	—	—	(0.16)	No	—	(606)
2006	36,500,000	—	—	—	(0.16)	No	—	110
2007	45,625,000	—	—	—	(0.16)	No	—	145
2008	45,750,000	—	—	—	(0.16)	No	—	156
2009	36,500,000	—	—	—	(0.16)	No	—	110
Counter-Swaps:								
2003	45,700,000	3.74	—	—	—	No	—	13,771
Locked-Swaps:								
2002	—	—	—	—	—	No	—	4,527
2003	—	—	—	—	—	No	—	16,107
Total Gas							31,126	(16,047)
Oil (bbls):								
Swaps:								
2002	184,000	25.76	—	—	—	Yes	—	(782)
2003	360,000	25.10	—	—	—	Yes	—	(1,112)
Cap-Swaps:								
2002	552,000	24.87	19.98	—	—	No	—	(2,849)
2003	3,015,000	28.10	—	—	—	No	—	(213)
Total Oil							—	(4,956)
Total Gas and Oil							$ 31,126(a)	$ (21,003)(a)

(a) After adjusting for the $31.1 million premium paid to Chesapeake by the counterparty at the inception of the straddle and strangle contracts (which is recorded in cash provided by operating activities on the accompanying consolidated statements of cash flows), the net value of the combined hedging portfolio at September 30, 2002 was $10.1 million.

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at September 30, 2002.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows ($ in thousands):

Fair value of contracts outstanding at January 1, 2002	$ 157,309
Change in fair value of contracts during period	(48,559)
Contracts realized or otherwise settled during the period	(84,150)
Fair value of new contracts when entered into during the period	(45,603)
Fair value of contracts outstanding at September 30, 2002	$ (21,003)

Risk management income (loss) related to our oil and gas derivatives is comprised of the following ($ in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Risk management income (loss):				
Change in fair value of derivatives not qualifying for hedge accounting	$ 8,056	$ 37,742	$ (34,474)	$ 102,793
Reclassification of gain on settled contracts	(16,764)	(6,440)	(52,471)	(9,996)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(54)	958	(2,236)	1,918
Total	$ (8,762)	$ 32,260	$ (89,181)	$ 94,715

The change in the fair value of our derivative instruments since January 1, 2002 resulted from an increase in market prices for natural gas and crude oil. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and gas as of the consolidated balance sheet dates. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

Based upon the market prices at September 30, 2002, we expect to transfer approximately $6.4 million of the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of September 30, 2002 are expected to mature by December 31, 2004, with the exception of the basis protection swaps which extend to 2009.

Interest Rate Hedging

We also utilize hedging strategies to manage interest rate exposure. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

In March 2002, we entered into an interest rate swap to convert a portion of our fixed rate debt to floating rate debt. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2002 – March 2004	$200,000,000	7.875%	U.S. six-month LIBOR in arrears plus 298.25 basis points

At the inception of the interest rate swap agreement, a portion of the interest rate swap was entered into to convert $129.0 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge under which the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. During the Current Quarter and Current Period, $21.3 million and $63.5 million, respectively, of the 7.875% senior notes were purchased and subsequently retired. In connection with the repurchase of the 7.875% senior notes, interest rate swap hedging gains of $0.4

million and $0.9 million were recognized in the Current Quarter and Current Period, respectively, and reduce the loss on repurchases of debt.

In July 2002, we closed the above interest rate swap for a gain of $7.5 million. As of September 30, 2002, the remaining balance to be amortized as a reduction to interest expense was $4.1 million. During the Current Period, $2.5 million was recognized as a reduction to interest expense.

In June 2002, we entered into an additional interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
July 2002 – July 2004	$100,000,000	4.000%	U.S. six-month LIBOR in arrears

In July 2002, we closed this interest rate swap for a gain of $1.1 million. During the Current Quarter, $0.1 million was recognized as a reduction to interest expense.

In April 2002, we entered into a swaption agreement in order to monetize the embedded call option in the remaining $142.7 million of our 8.5% senior notes. We received $7.8 million from the counterparty at the time we entered into this agreement. The terms of the swaption are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004 – March 2012	$142,665,000	8.500%	U.S. six-month LIBOR plus 75 basis points

Under the terms of the swaption agreement, the counterparty will have the option to initiate an interest rate swap on March 11, 2004 pursuant to the terms shown above. If the counterparty chooses to initiate the interest rate swap, the payments under the swap will coincide with the semi-annual interest payments on our 8.5% senior notes which are paid on September 15 and March 15 of each year. On each payment date, if the fixed rate exceeds the floating rate, we will pay the counterparty, and if the floating rate exceeds the fixed rate, the counterparty will pay us accordingly. If the counterparty does not choose to initiate the interest rate swap, the swaption agreement will expire and no future obligations will exist for either party.

According to SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and our swaption agreement. Accordingly, the mark-to-market value of the swaption is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to the debt's carrying value. Any change in the fair value of the swaption resulting from ineffectiveness is recorded currently in the consolidated statements of operations as risk management income (loss).

We have recorded a decrease in the carrying value of the debt of $20.3 million during the Current Period related to the swaption as of September 30, 2002. Of this amount, $21.4 million represents a decline in the fair value of the swaption, offset by a loss of $1.1 million from estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 5 of the notes to consolidated financial statements included in this report for the adjustments made to the carrying value of the debt at September 30, 2002. Results of the swaption will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

Risk management income related to our fair value hedges is comprised of the following ($ in thousands):

	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2002
Risk management income:		
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 2,292	$ 4,593
Reclassification of gains on settled contracts to interest expense	(576)	(1,307)
Ineffective portion of derivatives qualifying for fair value hedge accounting	—	(1,100)
Total	$ 1,716	$ 2,186

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. The fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	September 30, 2002								
	Years of Maturity								
	2002	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
	($ in millions)								
Liabilities:									
Long-term debt, including current portion — fixed rate	$ —	$ —	$ 86.5	$ —	$ —	$ —	$1,442.6	$1,529.1(a)	$1,529.4
Average interest rate	—	—	7.9%	—	—	—	8.4%	8.3%	8.3%
Long-term debt — variable rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Average interest rate	—	—	—	—	—	—	—	—	—

(a) This amount does not include the discount included in long-term debt of ($16.4) million, the value of the interest rate swaps of $1.8 million and the value of the swaption of ($20.3) million.

Item 4. ***Controls and Procedures***

Within the 90-day period prior to the filing of this report, the company carried out an evaluation, under the supervision and with the participation of the company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the company's disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures are effective in timely alerting them to material information relating to the company (including its consolidated subsidiaries) required to be included in the company's periodic SEC filings. There have been no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

We are subject to ordinary routine litigation incidental to our business, none of which is expected to have a material adverse effect on Chesapeake. In addition, Chesapeake is a defendant in other pending actions which are described in Note 3 of the notes to the consolidated financial statements included in this report and Item 3 of our Annual Report on Form 10-K for the year ended December 31, 2001.

Item 2. ***Changes in Securities and Use of Proceeds***

Not applicable

Item 3. ***Defaults Upon Senior Securities***

Not applicable

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

Not applicable

Item 5. ***Other Information***

Not applicable

Item 6. ***Exhibits and Reports on Form 8-K***

(a) *Exhibits*

The following exhibits are filed as a part of this report:

Exhibit Number	Description
4.1.2	Tenth Supplemental Indenture dated as of June 28, 2002 to Indenture dated as of March 15, 1997 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 7.875% Senior Notes due 2004. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's registration statement on Form S-4 (No.333-99289).
4.1.3	Eleventh Supplemental Indenture dated as of July 8, 2002 to Indenture dated as of March 15, 1997 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 7.875% Senior Notes due 2004. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's registration statement on Form S-4 (No.333-99289).
4.2.2	Tenth Supplemental Indenture dated as of June 28, 2002 to Indenture dated as of March 15, 1997 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.2.3 Eleventh Supplemental Indenture dated as of July 8, 2002 to Indenture dated as of March 15, 1997 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.3.2 Fifth Supplemental Indenture dated as of June 28, 2002 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.3.3 Sixth Supplemental Indenture dated July 8, 2002 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.3.3 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.4.2 Second Supplemental Indenture dated as of June 28, 2002 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.375% Senior Notes due 2008. Incorporated herein by reference to Exhibit 4.4.2 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.4.3 Third Supplemental Indenture dated as of July 8, 2002 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.375% Senior Notes due 2008. Incorporated herein by reference to Exhibit 4.4.3 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.6.2 Consent and waiver letter dated August 2, 2002 with respect to $225,000,000 Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Parabas and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and other lenders party thereto. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289).

4.6.3 Third Amendment dated September 20, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.

4.6.4 Fourth Amendment dated November 4, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.

4.14	Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, with respect to 9% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's registration statement on Form S-4 (No. 333-99289).
12.1	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
21	Subsidiaries of Chesapeake. Incorporated herein by reference to Exhibit 21 to Chesapeake's registration statement of Form S-4 (No. 333-99389).
99.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, 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*

During the quarter ended September 30, 2002, we filed the following current reports on Form 8-K:

On July 1, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release on June 28, 2002 announcing the completion of our acquisition of Canaan Energy Corporation and the declaration of a quarterly cash dividend on our preferred stock. Under Item 9, we furnished comments of our Chairman and Chief Executive Officer regarding the Canaan acquisition.

On July 11, 2002, we filed a current report on Form 8-K furnishing under Item 9 that we had issued a press release on July 10, 2002 and furnishing the dates for our second quarter 2002 earnings release and conference call included in the press release.

On July 22, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had announced a significant gas discovery in the Greater Mayfield area of western Oklahoma's Anadarko Basin. We furnished under Item 9 additional information on the discovery well and area, a management summary and additional earnings release and conference call information.

On July 25, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release on July 25, 2002 announcing second quarter 2002 earnings and including information on earnings, drilling, recent and pending acquisitions and the earnings conference call. Under Item 9, we furnished updated operational and financial guidance for 2002.

On July 30, 2002, we filed a current report on Form 8-K/A, amending the Form 8-K we filed July 25, 2002, to restate certain disclosures reported under Item 5 as disclosures under Item 9.

On July 31, 2002, we filed a current report on Form 8-K including as exhibits under Item 7 consents of reserve engineers.

On August 6, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release on August 5, 2002 announcing the commencement of a private offering of $250 million senior notes due 2012 and stating the expected use of proceeds from the issuance.

On August 7, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release on August 7, 2002 announcing the pricing of a private offering of $250 million senior notes due 2012 and stating the expected use of proceeds from the issuance.

On August 8, 2002, we filed a current report on Form 8-K/A amending the Form 8-K we filed August 7, 2002 to restate the use of proceeds from our offering of senior notes due 2012.

On August 15, 2002, we filed a current report on Form 8-K furnishing under Item 9 certifications of our chief executive officer and chief financial officer required by Section 906 of the Sarbanes-Oxley Act of 2002, which certifications accompanied our Form 10-Q filed August 5, 2002.

On September 3, 2002, we filed a current report on Form 8-K reporting under Item 9 that we had issued a press release on September 3, 2002 and furnishing information from the press release about our 2002 and 2003 hedging positions and increases in our proved reserves and production as a result of the completion of recent oil and gas acquisitions.

On September 17, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release on September 17, 2002 announcing the election of Charles T. Maxwell to our board of directors.

On September 20, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release on September 20, 2002 announcing that our board of directors had declared quarterly cash dividends on our common stock and preferred stock and the company's intention to dispose of its Permian Basin assets. The Form 8-K also furnished under Item 9 related comments of our chairman and chief executive officer.

SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION
(Registrant)

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman and Chief Executive Officer

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and
Chief Financial Officer

Date: November 7, 2002

CERTIFICATION

I, Aubrey K. McClendon, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Chesapeake Energy Corporation;

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 quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 7, 2002

/s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman and Chief Executive Officer

CERTIFICATION

I, Marcus C. Rowland certify that:

1. I have reviewed this quarterly report on Form 10-Q of Chesapeake Energy Corporation;

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 quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 7, 2002

/s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and Chief Financial Officer

INDEX TO EXHIBITS

Exhibit Number	Description
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4.3.3	Sixth Supplemental Indenture dated July 8, 2002 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.3.3 to Chesapeake's registration statement on Form S-4 (No.333-99289).
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Incorporated herein by reference to Exhibit 4.4.3 to Chesapeake's registration statement on Form S-4 (No.333-99289).

4.6.2 Consent and waiver letter dated August 2, 2002 with respect to $225,000,000 Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Parabas and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and other lenders party thereto. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake's registration statement on Form S-4 (No. 333-99289).

4.6.3 Third Amendment dated September 20, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.

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4.14 Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York, with respect to 9% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.14 to Chesapeake's registration statement on Form S-4 (No. 333-99289).

12.1 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.

21 Subsidiaries of Chesapeake. Incorporated herein by reference to Exhibit 21 to Chesapeake's registration statement of Form S-4 (No. 333-99389).

99.1 Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.2 Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification Pursuant to 18 U.S.C Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 99.1

**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 Chesapeake Energy Corporation (the "Company") on Form 10-Q for the period ended September 30, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Aubrey K. McClendon, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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.

/s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman and Chief Executive Officer

Date: November 7, 2002

Exhibit 99.2

**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 Chesapeake Energy Corporation (the "Company") on Form 10-Q for the period ended September 30, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Marcus C. Rowland, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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.

/s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and Chief Financial Officer

Date: November 7, 2002