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, 2003

[ ] 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 [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). YES [X] NO [ ]

At November 7, 2003, there were 216,521,292 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2003

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2003	December 31, 2002
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 38,478	$ 247,637
Restricted cash	—	82
Accounts receivable:		
Oil and gas sales	181,562	109,246
Joint interest, net of allowance of $2,650,000 and $1,433,000, respectively	28,425	22,760
Short-term derivatives	2,152	16,498
Related parties	5,179	2,155
Other	30,044	13,471
Deferred income tax asset	—	8,109
Short-term derivative instruments	75,681	—
Inventory and other	15,209	15,359
Total Current Assets	376,730	435,317
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full cost accounting:		
Evaluated oil and gas properties	5,826,209	4,334,833
Unevaluated properties	175,262	72,506
Less: accumulated depreciation, depletion and amortization	(2,377,814)	(2,123,773)
	3,623,657	2,283,566
Other property and equipment	207,972	154,092
Less: accumulated depreciation and amortization	(56,352)	(47,774)
Total Property and Equipment	3,775,277	2,389,884
OTHER ASSETS:		
Deferred income tax asset	—	2,071
Long-term derivative instruments	42,247	2,666
Long-term investments	29,233	9,075
Other assets	34,002	36,595
Total Other Assets	105,482	50,407
TOTAL ASSETS	$ 4,257,489	$ 2,875,608
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 140,199	$ 86,001
Accrued interest	48,592	35,025
Short-term derivative instruments	33,804	33,697
Income tax payable	13,476	—
Other accrued liabilities	89,187	56,465
Revenues and royalties due others	100,919	54,364
Total Current Liabilities	426,177	265,552
OTHER LIABILITIES:		
Long-term debt, net	2,024,336	1,651,198
Revenues and royalties due others	15,491	13,797
Long-term derivative instruments	109	30,174
Asset retirement obligation	46,540	—
Other liabilities	9,142	7,012
Deferred income taxes payable	151,324	—
Total Other Liabilities	2,246,942	1,702,181
CONTINGENCIES AND COMMITMENTS (Note 3)		
SHAREHOLDERS' EQUITY:		
Preferred Stock, $0.01 par value, 10,000,000 shares authorized,		
6.75% cumulative convertible preferred stock, 2,998,000 shares issued and outstanding at September 30, 2003 and December 31, 2002, entitled in liquidation to $149.9 million	149,900	149,900
6.00% cumulative convertible preferred stock, 4,600,000 and 0 shares issued and outstanding at September 30, 2003 and December 31, 2002, entitled in liquidation to $230.0 million	230,000	—
Common Stock, $.01 par value, 350,000,000 shares authorized, 221,474,389 and 194,936,912 shares issued at September 30, 2003 and December 31, 2002, respectively	2,215	1,949
Paid-in capital	1,390,730	1,205,554
Accumulated deficit	(222,338)	(426,085)
Accumulated other comprehensive income (loss), net of tax of $(34,294,000) and $2,307,000, respectively	55,954	(3,461)
Less: treasury stock, at cost; 5,071,571 and 4,792,529 common shares at September 30, 2003 and December 31, 2002, respectively	(22,091)	(19,982)
Total Shareholders' Equity	1,584,370	907,875
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 4,257,489	$ 2,875,608

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 345,587	$ 154,249	$ 951,125	$ 367,810
Oil and gas marketing sales	108,962	42,216	309,566	112,334
Total Revenues	454,549	196,465	1,260,691	480,144
OPERATING COSTS:				
Production expenses	35,944	24,950	101,664	71,252
Production taxes	21,638	6,807	57,336	19,934
General and administrative	5,589	3,777	17,254	11,930
Oil and gas marketing expenses	105,849	41,148	302,064	108,836
Oil and gas depreciation, depletion and amortization	97,947	58,334	266,131	157,731
Depreciation and amortization of other assets	4,841	3,727	12,647	10,489
Total Operating Costs	271,808	138,743	757,096	380,172
INCOME FROM OPERATIONS	182,741	57,722	503,595	99,972
OTHER INCOME (EXPENSE):				
Interest and other income	(188)	1,806	1,356	7,343
Interest expense	(40,851)	(26,599)	(115,891)	(77,779)
Loss on investment in Seven Seas	—	(4,770)	—	(4,770)
Loss on repurchases of Chesapeake debt	—	(489)	—	(1,353)
Total Other Income (Expense)	(41,039)	(30,052)	(114,535)	(76,559)
INCOME BEFORE INCOME TAX AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	141,702	27,670	389,060	23,413
INCOME TAX EXPENSE:				
Current	330	—	330	—
Deferred	53,513	11,070	147,511	9,366
Total Income Tax Expense	53,843	11,070	147,841	9,366
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	87,859	16,600	241,219	14,047
Cumulative effect of accounting change, net of income taxes of $1,464,000	—	—	2,389	—
NET INCOME	87,859	16,600	243,608	14,047
Preferred stock dividends	(5,979)	(2,526)	(15,484)	(7,588)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 81,880	$ 14,074	$ 228,124	$ 6,459
EARNINGS PER COMMON SHARE — BASIC:				
Income before cumulative effect of accounting change	$ 0.38	$ 0.08	$ 1.08	$ 0.04
Cumulative effect of accounting change	—	—	0.01	—
Net income	$ 0.38	$ 0.08	$ 1.09	$ 0.04
EARNINGS PER COMMON SHARE — ASSUMING DILUTION:				
Income before cumulative effect of accounting change	$ 0.33	$ 0.08	$ 0.95	$ 0.04
Cumulative effect of accounting change	—	—	0.01	—
Net income	$ 0.33	$ 0.08	$ 0.96	$ 0.04
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):				
Basic	216,080	166,144	209,394	165,829
Assuming dilution	265,545	171,182	253,567	171,540

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 243,608	$ 14,047
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	273,479	164,365
Unrealized (gains) losses on derivatives	(28,335)	86,995
Deferred income taxes	147,841	9,366
Amortization of loan costs and bond discount	6,358	3,626
Cumulative effect of accounting change	(2,389)	—
Loss on repurchases of Chesapeake debt	—	1,353
Loss on investment in Seven Seas	—	4,770
Other	929	(223)
Cash provided by operating activities before changes in assets and liabilities	641,491	284,299
Changes in assets and liabilities	12,026	69,359
Cash provided by operating activities	653,517	353,658
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of oil and gas properties	(501,865)	(252,756)
Acquisition of unproved oil and gas properties	(130,434)	(46,808)
Acquisition of proved oil and gas properties	(909,475)	(291,366)
Sales of proved oil and gas properties	21,218	1,211
Investment in Pioneer Drilling	(20,000)	—
Liquidation proceeds on investment in Seven Seas	5,333	—
Additions to long-term investments	(5,750)	(2,408)
Proceeds from sale of RAM Energy notes	—	4,215
Additions to other property, plant and equipment and other	(59,795)	(29,271)
Cash used in investing activities	(1,600,768)	(617,183)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	485,000	95,818
Payments on long-term borrowings	(413,000)	(95,818)
Cash received from issuance of senior notes	297,306	245,984
Cash paid for issuance costs of senior notes	(6,367)	(3,671)
Proceeds from issuance of preferred stock, net of issuance costs	222,893	—
Proceeds from issuance of common stock, net of issuance costs	177,444	—
Net increase in outstanding payments in excess of cash balances	6,341	—
Cash paid for common stock dividend	(19,679)	—
Cash paid for preferred stock dividend	(14,872)	(7,649)
Cash paid to repurchase senior notes	—	(63,541)
Cash paid for premium on repurchase of senior notes	—	(1,869)
Cash paid for treasury stock	(2,109)	—
Cash received from exercise of stock options and warrants	7,787	2,129
Other	(2,652)	(74)
Cash provided by financing activities	738,092	171,309
NET DECREASE IN CASH AND CASH EQUIVALENTS	(209,159)	(92,216)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	247,637	117,594
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 38,478	$ 25,378

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	($ in thousands)			
Net income	$ 87,859	$ 16,600	$ 243,608	$ 14,047
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments	60,551	(3,887)	23,692	(16,859)
Reclassification of (gain) or loss on settled contracts	(14,032)	(3,274)	39,320	(19,044)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(3,311)	32	(3,597)	1,342
Other	—	(49)	—	(49)
Comprehensive income (loss)	$ 131,067	$ 9,422	$ 303,023	$ (20,563)

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

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, 2003 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, 2002 (the "Prior Quarter" and “Prior Period”, respectively) and the three and nine months ended September 30, 2003 (the "Current Quarter" and “Current Period”, respectively). As discussed in Note 16 to the consolidated financial statements included in Form 10-K/A, we have reclassified certain amounts in our previously reported condensed consolidated financial statements for the three and nine months ended September 30, 2002. These reclassifications had no effect on previously reported net income or net income per share.

Stock Options

Chesapeake has elected to follow APB No. 25, *Accounting for Stock Issued to Employees,* and related interpretations in accounting for its employee stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. In March 2000, the Financial Accounting Standards Board issued FASB Interpretation No. 44, which provided clarification regarding the application of APB No. 25. FIN 44 specifically addressed the accounting consequences of various modifications to the terms of a previously granted fixed–price stock option. Pursuant to FIN 44, we recognized compensation expense (income) of $147,300, $512,600, $(73,000) and $89,500 in the Current Quarter, the Current Period, the Prior Quarter and the Prior Period, respectively, as a result of modifications to fixed-price stock options that were made during the years ended December 31, 2001 and 2000. No compensation income or expense has been recognized for stock options issued in 2003 or 2002 because the exercise price of the stock options granted under the plans equaled the market price of the underlying stock on the date of grant and there have been no modifications to these options.

Presented below is pro forma financial information assuming that Chesapeake had applied the fair value method under SFAS No. 123:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
	($ in thousands)			
Net Income				
As reported [(1)]	$ 87,859	$ 16,600	$ 243,608	$ 14,047
Compensation expense, net of tax	(2,987)	(2,335)	(8,000)	(6,488)
Pro forma	$ 84,872	$ 14,265	$ 235,608	$ 7,559
Basic earnings per common share				
As reported	$ 0.38	$ 0.08	$ 1.09	$ 0.04
Compensation expense, net of tax	(0.01)	(0.01)	(0.04)	(0.04)
Pro forma	$ 0.37	$ 0.07	$ 1.05	$ —
Diluted earnings per common share				
As reported	$ 0.33	$ 0.08	$ 0.96	$ 0.04
Compensation expense, net of tax	(0.01)	(0.01)	(0.03)	(0.04)
Pro forma	$ 0.32	$ 0.07	$ 0.93	$ —

(1) Net income includes adjustments related to FIN 44 of $147,300, $512,600, $(73,000) and $89,500 of expense (income) in the Current Quarter, the Current Period, the Prior Quarter and the Prior Period, respectively.

For purposes of the pro forma disclosures, the estimated fair value of the options is amortized to expense over the options’ vesting period, which is four years. Because our stock options vest over four years and additional awards are typically made each year, the above pro forma disclosures are not likely to be representative of the effects on pro forma net income for future periods.

Critical Accounting Policies

We consider accounting policies related to stock options, hedging, oil and gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K/A for the year ended December 31, 2002, except for our accounting policy related to stock options which is summarized in Note 1 of the notes to the consolidated financial statements included in our annual report on Form 10-K/A.

Statement of Financial Accounting Standards No. 141, *Business Combinations* and Statement of Financial Accounting Standards No. 142, *Goodwill and Intangible Assets* were issued by the Financial Accounting Standards Board in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment.

One interpretation being considered relative to these standards is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties as intangible assets on our condensed consolidated balance sheets. In addition, the disclosures required by SFAS 141 and 142 relative to intangibles would be included in the notes to the condensed consolidated financial statements. Historically, we, like many other oil and gas companies, have included these rights as part of oil and gas properties, even after SFAS 141 and 142 became effective.

As it applies to companies like us that have adopted full cost accounting for oil and gas activities, we understand that this interpretation of SFAS 141 and 142 would only affect our balance sheet classification of proved oil and gas leaseholds acquired after June 30, 2001 and all of our unproved oil and gas leaseholds. We would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because we did not separately value or account for these costs prior to the adoption date of SFAS 141. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and gas reserves would continue to be amortized in accordance with full cost accounting rules.

As of September 30, 2003 and December 31, 2002, we had undeveloped leaseholds of approximately $175.3 million and $72.5 million, respectively, that would be classified on our condensed consolidated balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $1,495.5 million and $581.9 million, respectively, that would be classified as "intangible developed leasehold" if we applied the interpretation discussed above.

We will continue to classify our oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as oil and gas properties until further guidance is provided.

2. Financial Instruments and Hedging Activities

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, 2003, our oil and gas derivative instruments were comprised of swaps, cap-swaps 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, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays 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.

- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a “cap” limiting the counterparty's exposure. In other words, there is no limit to Chesapeake’s exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written option does not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.
- Basis protection swaps are arrangements that guarantee a price differential of oil or 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.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap or cap-swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap’s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that, collectively, the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of a counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in the value of the corresponding counter-swap.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets, to the extent that a legal right of setoff exists.

Gains or losses from the oil and gas derivative transactions are reflected as adjustments to oil and gas sales on the condensed consolidated statement of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e. temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales were $0.6 million, $(8.8) million, $33.7 million and $(89.2) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. Amounts relating to ineffectiveness on cash flow hedges consisted of a gain of $5.3 million in the Current Quarter, a loss of $0.1 million in the Prior Quarter, a gain of $5.8 million in the Current Period and a loss of $2.2 million in the Prior Period.

The estimated fair values of our oil and gas derivative instruments as of September 30, 2003 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2003 ($ in thousands)
Derivative assets (liabilities):	
Fixed-price gas swaps	$ 92,318
Fixed-price gas cap-swaps	(14,720)
Fixed-price gas counter-swaps	12,070
Fixed-price gas locked swaps	2,677
Gas basis protection swaps	28,126
Fixed-price crude oil cap-swaps	(3,245)
Estimated fair value	$ 117,226

Based upon the market prices at September 30, 2003, we expect to transfer approximately $44.3 million of the gain included in accumulated other comprehensive income to earnings during the next 12 months when the hedged oil or gas production is sold. All transactions hedged as of September 30, 2003 are for periods extending through 2007, 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:

	2003 ($ in thousands)
Fair value of contracts outstanding at January 1	$ (14,533)
Change in fair value of contracts during the period	57,807
Contracts realized or otherwise settled during the period	73,952
Fair value of new contracts when entered into during the period	—
Fair value of contracts outstanding at September 30	$ 117,226

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 July 2002, we closed two interest rate swaps for a cash settlement of $8.6 million. As of September 30, 2003, the remaining balance to be amortized as a reduction to interest expense was $0.3 million. During the Current Quarter and Current Period, $0.1 million and $0.4 million, respectively, were recorded as reductions to interest expense.

On August 13, 2003, we entered into an interest rate swap having the following terms:

Term	Notional Amount	Fixed Rate	Floating Rate
August 2003 – August 2005	$100,000,000	2.735%	U.S. six-month LIBOR in arrears

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. Payments under this interest rate swap will be made on February 15 and August 15 of each year beginning February 15, 2004. At September 30, 2003, this interest rate swap had a fair value of $1.2 million.

On August 22, 2003, we entered into an additional interest rate swap having the following terms:

Term	Notional Amount	Fixed Rate	Floating Rate
August 2003 – August 2005	$100,000,000	3.000%	U.S. six-month LIBOR in arrears

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. Payments under this interest rate swap will be made on February 27 and August 27 of each year beginning February 27, 2004. At September 30, 2003, this interest rate swap had a fair value of $1.6 million.

In March 1997, Chesapeake issued $150.0 million of 8.5% senior notes due 2012, of which $7.3 million were subsequently repurchased and retired. The 8.5% senior notes include a "call option" whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. This call option, also referred to as a right of optional redemption, allows Chesapeake to redeem the notes prior to their stated maturity date beginning in March 2004. This right of optional redemption has value depending upon changes in interest rates. Due to a decline in interest rates, Chesapeake effectively sold this optional redemption right to an unrelated third party (or counterparty) for $7.8 million in April 2002. In exchange for the $7.8 million, Chesapeake gave the counterparty the option to elect whether or not to enter into an interest rate swap with Chesapeake on March 11, 2004. This transaction is more commonly referred to as a swaption. The terms of the interest rate swap, if executed by the counterparty, would be 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

The interest rate swap would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap on March 11, 2004, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

This transaction does not alter Chesapeake's ability to redeem the 8.5% senior notes. Instead, it locks-in the economics of a future call. If interest rates are high and the swaption is not "in-the-money", the counterparty will likely not elect to enter into the interest rate swap, the swaption will expire, and Chesapeake will amortize the $7.8 million premium as a reduction to interest expense over the remaining life of the notes. If interest rates are low and the swaption is "in-the-money", the counterparty will likely exercise the swaption and force Chesapeake to settle the transaction at the then current value of the interest rate swap, and Chesapeake will amortize both the $7.8 million premium and the amount paid to the counterparty to interest expense over the remaining life of the notes. If Chesapeake elects to refinance the 8.5% senior notes, any unamortized premium or loss remaining related to the swaption would be included in the gain (or loss) on the early extinguishment of debt.

According to SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and the swaption agreement. The fair value of the swaption is recorded on the condensed consolidated balance sheets as a liability, and the debt's carrying amount is adjusted by the change in the fair value of the call option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense.

During the Current Quarter, we exchanged and subsequently retired $32.0 million of our 8.5% senior notes. In connection with this retirement, we have removed the designation of the corresponding portion of the swaption agreement as a fair value hedge in accordance with SFAS 133. We recorded a $3.3 million increase to the fair value of the debt to reflect the portion of the 8.5% senior notes exchanged and subsequently retired in the Current Quarter. Temporary fluctuations in the fair value of the portion of the swaption no longer designated as a fair value hedge are recorded as adjustments to interest expense. We recorded a $2.0 million unrealized loss in interest expense during the Current Quarter due to a decline in the fair value of the portion of the swaption no longer designated as a fair value hedge.

We recorded an adjustment to the carrying amount of the debt of $15.4 million as of September 30, 2003, which represents the temporary fluctuations in the fair value of the call option included in senior notes. Since the inception of the swaption, we have recorded a change in the fair market value of the swaption from a $7.8 million liability to a $33.8 million liability, an increase of $26.0 million. After giving effect to the removal of the designation of a portion of the swaption as a fair value hedge under SFAS 133 as described previously, the difference of $5.3 million represents ineffectiveness which has been recorded as additional interest expense.

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 values 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, fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt, excluding the value of the interest rate swaps and the call option on the 8.5% senior notes, at September 30, 2003 and December 31, 2002 was $1,965.1 million and $1,669.3 million, respectively, compared to approximate fair values of $2,129.9 million and $1,744.7 million, respectively. The carrying amount for our 6.75% convertible preferred stock at September 30, 2003 and December 31, 2002 was $149.9 million, with a fair value of $226.8 million and $181.5 million, respectively. The carrying amount of our 6.00% convertible preferred stock at September 30, 2003 was $230.0 million, with a fair value of approximately $322.0 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. 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 and equity instruments and accounts receivable. 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 industry concentration 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 and may at times exceed the federally insured limits.

3. Contingencies and Commitments

Royalty Owner Litigation. Royalty owners have commenced litigation against a number of oil and gas producers claiming that amounts paid for production attributable to the royalty owners' interest violated the terms of applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the leases, and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. Typically this litigation has taken the form of class action suits. There are presently four such suits filed against Chesapeake, two in Texas and two in Oklahoma. No class has been certified in any of them. In one of the Oklahoma cases, we determined that a portion of the marketing fee we had charged royalty owners should be refunded. We have deposited with the court the aggregate amount of the fees we estimated should be refunded, $3.6 million, in an interest-bearing account for distribution to affected royalty owners. This amount has been charged to general and administrative expenses, of which $0.3 million was charged in the Current Period and the remainder was recorded in 2002. We do not believe any other claims made by royalty owners in the cases pending against us are valid. Even if the claims were upheld, we believe any damages awarded would not be material. This is a developing area of the law, however, and as new cases are decided, our potential liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor 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 our consolidated financial position or results of operations.

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and various other senior management personnel, which provide for annual base salaries, bonus compensation and various benefits. The agreements provide for the continuation of salary and benefits for varying terms in the event of termination of employment without cause. The agreements with the chief executive officer and chief operating officer have terms of five years commencing July 1, 2002. The term of each agreement is automatically extended for one additional year on each June 30 unless one of the parties provides 30 days notice of non-extension. The agreements with the chief financial officer and other senior managers expire on June 30, 2006. The company's employment agreements for executive officers provide for payments in the event of a change of control. The chief executive officer and chief operating officer are each entitled to receive a payment in the amount of five times his base compensation and the prior year's benefits, plus a tax gross-up payment, and the chief financial officer and other officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year.

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 conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume the liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at September 30, 2003.

4. Net Income (Loss) 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 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 Current Quarter, the Prior Quarter, the Current Period and the Prior Period, outstanding warrants to purchase 0.4 million, 1.1 million, 0.4 million and 1.1 million shares of common stock at a weighted-average exercise price of $14.55, $12.61, $14.55 and $12.61, respectively, were antidilutive because the exercise prices of the warrants were greater than the average market price of the common stock.
- For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, outstanding options to purchase 0.2 million, 7.8 million, 1.3 million and 0.5 million shares of common stock at a weighted-average exercise price of $19.21, $6.56, $11.60 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 Prior Quarter and Prior Period do not include the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares) and the Prior Period does not include the common stock equivalent of preferred stock outstanding prior to conversion of 7,611 shares, as the effects were antidilutive.

Reconciliations for the three and nine months ended September 30, 2003 and 2002 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Three Months Ended September 30, 2003:			
Basic EPS			
Income available to common shareholders	$ 81,880	216,080	$ 0.38
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares outstanding during the period:			
Preferred dividends	5,979	—	
Common shares assumed issued for 6.00% preferred stock	—	22,358	
Common shares assumed issued for 6.75% preferred stock	—	19,468	
Employee stock options	—	7,639	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 87,859	265,545	$ 0.33
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 Nine Months Ended September 30, 2003:			
Basic EPS			
Income available to common shareholders	$ 228,124	209,394	$ 1.09
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares outstanding during the period:			
Preferred dividends	15,484	—	
Common shares assumed issued for 6.00% preferred stock	—	17,198	
Common shares assumed issued for 6.75% preferred stock	—	19,468	
Employee stock options	—	7,507	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 243,608	253,567	$ 0.96
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

5. Senior Notes and Revolving Credit Facility

At September 30, 2003, our long-term debt consisted of the following ($ in thousands):

7.875% senior notes, due 2004	$ 42,137(1)
8.375% senior notes, due 2008	222,150
8.125% senior notes, due 2011	800,000
8.500% senior notes, due 2012	110,669
9.000% senior notes, due 2012	300,000
7.500% senior notes, due 2013	300,000
7.750% senior notes, due 2015	213,001
Revolving bank credit facility	72,000
Discount on senior notes	(22,816)
Call option on 8.5% senior notes	(15,418)(2)
Interest rate swaps	2,613
Total	$2,024,336

(1) This amount has been classified as long-term debt based on our ability to satisfy this obligation with funding from our bank credit facility.
(2) See Note 2 for further discussion of the call option.

On March 5, 2003, we issued $300.0 million principal amount of 7.50% senior notes due 2013, which were exchanged on November 5, 2003 for substantially identical notes registered under the Securities Act of 1933**.**

On July 16, 2003, we issued an additional $29.5 million of our 7.75% senior notes due 2015 in exchange for $27.9 million of our 8.375% senior notes due 2008 and $0.5 million of accrued interest, pursuant to a privately negotiated transaction. The $27.9 million of 8.375% senior notes due 2008 were retired upon receipt.

On August 5, 2003, we issued an additional $33.5 million of our 7.75% senior notes due 2015 and accrued interest of $0.1 million in exchange for $32.0 million of our 8.5% senior notes due 2012 and $1.1 million of accrued interest, pursuant to a privately negotiated transaction. The $32.0 million of 8.5% senior notes were retired upon receipt.

On September 30, 2003, we had a $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. As of September 30, 2003, we had $72 million in outstanding borrowings under this facility and were using $10.3 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 our senior unsecured long-term debt ratings issued by Standard & Poor's Ratings Services and Moody's Investor Service. The unused portion of the facility is subject to an annual commitment fee also based on our senior unsecured long-term debt ratings. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically.

The credit agreement contains various covenants and restrictive provisions which limit 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 and create liens. The credit agreement 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 for the trailing twelve month period of at least 2.5 to 1. At September 30, 2003, our current ratio was 1.5 to 1 and our fixed charge coverage ratio was 4.4 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 agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $25.0 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; 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. We may redeem the senior notes at any time at specified make-whole or redemption prices as provided in the indentures.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding 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 parent, guarantor subsidiaries and non-guarantor subsidiaries. Chesapeake Energy Marketing, Inc., Mayfield Processing, L.L.C. and MidCon Compression L.P. are wholly-owned marketing subsidiaries which are not guarantors of the senior notes. Chesapeake Energy Marketing, Inc. was a non-guarantor subsidiary for all periods presented. Mayfield Processing L.L.C. and MidCon Compression L.P. were established as non-guarantor subsidiaries during the Current Quarter. All of our other wholly-owned subsidiaries were guarantor subsidiaries during all periods presented.

CONDENSED CONSOLIDATED BALANCE SHEET
AS OF SEPTEMBER 30, 2003
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (206)	$ 38,644	$ 40	$ —	$ 38,478
Accounts receivable	181,755	126,981	11,123	(74,649)	245,210
Short-term derivative receivable	2,152	—	—	—	2,152
Short-term derivative instruments	72,936	—	2,745	—	75,681
Inventory and other	13,692	1,512	5	—	15,209
Total Current Assets	270,329	167,137	13,913	(74,649)	376,730
PROPERTY AND EQUIPMENT:					
Evaluated oil and gas properties	5,826,209	—	—	—	5,826,209
Unevaluated properties	175,262	—	—	—	175,262
Other property and equipment	77,133	51,549	79,290	—	207,972
Less: accumulated depreciation, depletion and amortization	(2,405,871)	(22,827)	(5,468)	—	(2,434,166)
Net Property and Equipment	3,672,733	28,722	73,822	—	3,775,277
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	848,198	(848,198)	—
Long-term derivative instruments	42,138	—	109	—	42,247
Long-term investments	—	—	29,233	—	29,233
Other assets	13,578	54	20,424	(54)	34,002
Total Other Assets	55,716	54	897,964	(848,252)	105,482
TOTAL ASSETS	$ 3,998,778	$ 195,913	$ 985,699	$ (922,901)	$ 4,257,489
LIABILITIES AND SHAREHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 134,637	$ 115,261	$ —	$ (109,699)	$ 140,199
Accrued interest	30	—	48,562	—	48,592
Other accrued liabilities	69,927	5,511	13,803	(54)	89,187
Short-term derivative instruments	—	—	33,804	—	33,804
Deferred income tax payable	—	—	13,476	—	13,476
Revenues and royalties due others	65,869	—	—	35,050	100,919
Total Current Liabilities	270,463	120,772	109,645	(74,703)	426,177
OTHER LIABILITIES:					
Long-term debt, net	72,000	—	1,952,336	—	2,024,336
Revenues and royalties due others	15,491	—	—	—	15,491
Long-term derivative instruments	—	—	109	—	109
Asset retirement obligation	46,540	—	—	—	46,540
Other liabilities	9,142	—	—	—	9,142
Deferred income tax payable (receivable)	273,740	3,438	(125,854)	—	151,324
Intercompany payables (receivables)	2,520,409	14,498	(2,534,907)	—	—
Total Other Liabilities	2,937,322	17,936	(708,316)	—	2,246,942
SHAREHOLDERS' EQUITY:					
Common stock	56	1	2,215	(57)	2,215
Preferred stock	—	—	379,900	—	379,900
Other	790,937	57,204	1,202,255	(848,141)	1,202,255
Total Shareholders' Equity	790,993	57,205	1,584,370	(848,198)	1,584,370
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 3,998,778	$ 195,913	$ 985,699	$ (922,901)	$ 4,257,489

CONDENSED CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2002
($ in thousands)

	Guarantor Subsidiary	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents, including restricted cash	$ (31,893)	$ 24,448	$ 255,164	$ —	$ 247,719
Accounts receivable	122,074	69,362	3,006	(46,810)	147,632
Short-term derivative receivable	16,498	—	—	—	16,498
Deferred income tax asset	—	—	8,109	—	8,109
Inventory and other	14,202	1,157	—	—	15,359
Total Current Assets	120,881	94,967	266,279	(46,810)	435,317
PROPERTY AND EQUIPMENT:					
Evaluated oil and gas properties	4,334,833	—	—	—	4,334,833
Unevaluated properties	72,506	—	—	—	72,506
Other property and equipment	64,475	30,818	58,799	—	154,092
Less: accumulated depreciation, depletion and amortization	(2,146,538)	(20,789)	(4,220)	—	(2,171,547)
Net Property and Equipment	2,325,276	10,029	54,579	—	2,389,884
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	357,698	(357,698)	—
Deferred income tax receivable (payable)	(124,455)	(1,941)	128,467	—	2,071
Long-term derivative instruments	2,666	—	—	—	2,666
Long-term investments	—	—	9,075	—	9,075
Other assets	20,246	57	16,349	(57)	36,595
Total Other Assets	(101,543)	(1,884)	511,589	(357,755)	50,407
TOTAL ASSETS	$ 2,344,614	$ 103,112	$ 832,447	$ (404,565)	$ 2,875,608
LIABILITIES AND SHAREHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 82,083	$ 71,316	$ —	$ (67,398)	$ 86,001
Accrued interest	—	—	35,025	—	35,025
Other accrued liabilities	46,231	1,960	8,326	(52)	56,465
Short-term derivative instruments	33,697	—	—	—	33,697
Revenues and royalties due others	33,776	—	—	20,588	54,364
Total Current Liabilities	195,787	73,276	43,351	(46,862)	265,552
OTHER LIABILITIES:					
Long-term debt, net	—	—	1,651,198	—	1,651,198
Revenues and royalties due others	13,797	—	—	—	13,797
Long-term derivative instruments	—	—	30,174	—	30,174
Other liabilities	5,687	1,325	—	—	7,012
Intercompany payables (receivable)	1,801,833	(1,677)	(1,800,151)	(5)	—
Total Other Liabilities	1,821,317	(352)	(118,779)	(5)	1,702,181
SHAREHOLDERS' EQUITY:					
Common stock	56	1	1,949	(57)	1,949
Preferred stock	—	—	149,900	—	149,900
Other	327,454	30,187	756,026	(357,641)	756,026
Total Shareholders' Equity	327,510	30,188	907,875	(357,698)	907,875
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 2,344,614	$ 103,112	$ 832,447	$ (404,565)	$ 2,875,608

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2003:					
REVENUES:					
Oil and gas sales	$ 345,587	$ —	$ —	$ —	$ 345,587
Oil and gas marketing sales	—	333,728	—	(224,766)	108,962
Total Revenues	345,587	333,728	—	(224,766)	454,549
OPERATING COSTS:					
Production expenses	35,944	—	—	—	35,944
Production taxes	21,638	—	—	—	21,638
General and administrative	4,424	879	286	—	5,589
Oil and gas marketing expenses	—	330,615	—	(224,766)	105,849
Oil and gas depreciation, depletion and amortization	97,947	—	—	—	97,947
Depreciation and amortization of other assets	2,805	918	1,118	—	4,841
Total Operating Costs	162,758	332,412	1,404	(224,766)	271,808
INCOME (LOSS) FROM OPERATIONS	182,829	1,316	(1,404)	—	182,741
OTHER INCOME (EXPENSE):					
Interest and other income	(26)	144	40,357	(40,663)	(188)
Interest expense	(38,566)	(11)	(42,937)	40,663	(40,851)
Equity in net earnings of subsidiaries	—	—	90,329	(90,329)	—
Total Other Income (Expense)	(38,592)	133	87,749	(90,329)	(41,039)
INCOME BEFORE INCOME TAXES	144,237	1,449	86,345	(90,329)	141,702
Income tax expense (benefit)	54,807	550	(1,514)	—	53,843
NET INCOME	$ 89,430	$ 899	$ 87,859	$ (90,329)	$ 87,859

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2002:					
REVENUES:					
Oil and gas sales	$ 154,249	$ —	$ —	$ —	$ 154,249
Oil and gas marketing sales	—	134,510	—	(92,294)	42,216
Total Revenues	154,249	134,510	—	(92,294)	196,465
OPERATING COSTS:					
Production expenses	24,950	—	—	—	24,950
Production taxes	6,807	—	—	—	6,807
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
Depreciation and amortization of other assets	2,668	487	572	—	3,727
Total Operating Costs	96,060	134,400	577	(92,294)	138,743
INCOME (LOSS) FROM OPERATIONS	58,189	110	(577)	—	57,722
OTHER INCOME (EXPENSE):					
Interest and other income	275	300	25,021	(28,560)	(2,964)
Interest expense	(27,991)	(2)	(27,166)	28,560	(26,599)
Loss on repurchases of Chesapeake debt	—	—	(489)	—	(489)
Equity in net earnings of subsidiaries	—	—	18,526	(18,526)	—
Total Other Income (Expense)	(27,716)	298	15,892	(18,526)	(30,052)
INCOME BEFORE INCOME TAXES	30,473	408	15,315	(18,526)	27,670
Income tax expense (benefit)	12,191	164	(1,285)	—	11,070
NET INCOME	$ 18,282	$ 244	$ 16,600	$ (18,526)	$ 16,600

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2003:					
REVENUES:					
Oil and gas sales	$ 951,125	$ —	$ —	$ —	$ 951,125
Oil and gas marketing sales	—	964,271	—	(654,705)	309,566
Total Revenues	951,125	964,271	—	(654,705)	1,260,691
OPERATING COSTS:					
Production expenses	101,664	—	—	—	101,664
Production taxes	57,336	—	—	—	57,336
General and administrative	14,133	2,123	998	—	17,254
Oil and gas marketing expenses	—	956,769	—	(654,705)	302,064
Oil and gas depreciation, depletion and amortization	266,131	—	—	—	266,131
Depreciation and amortization of other assets	7,572	2,038	3,037	—	12,647
Total Operating Costs	446,836	960,930	4,035	(654,705)	757,096
INCOME (LOSS) FROM OPERATIONS	504,289	3,341	(4,035)	—	503,595
OTHER INCOME (EXPENSE):					
Interest and other income	(28)	610	117,102	(116,328)	1,356
Interest expense	(110,511)	(11)	(121,697)	116,328	(115,891)
Equity in net earnings of subsidiaries	—	—	248,959	(248,959)	—
Total Other Income (Expense)	(110,539)	599	244,364	(248,959)	(114,535)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	393,750	3,940	240,329	(248,959)	389,060
Income tax expense (benefit)	149,623	1,497	(3,279)	—	147,841
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	244,127	2,443	243,608	(248,959)	241,219
Cumulative effect of accounting change, net of tax	2,389	—	—	—	2,389
NET INCOME	$ 246,516	$ 2,443	$ 243,608	$ (248,959)	$ 243,608

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2002:					
REVENUES:					
Oil and gas sales	$ 367,810	$ —	$ —	$ —	$ 367,810
Oil and gas marketing sales	—	362,939	—	(250,605)	112,334
Total Revenues	367,810	362,939	—	(250,605)	480,144
OPERATING COSTS:					
Production expenses	71,252	—	—	—	71,252
Production taxes	19,934	—	—	—	19,934
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
Depreciation and amortization of other assets	7,323	1,257	1,909	—	10,489
Total Operating Costs	266,536	362,061	2,180	(250,605)	380,172
INCOME (LOSS) FROM OPERATIONS	101,274	878	(2,180)	—	99,972
OTHER INCOME (EXPENSE):					
Interest and other income	1,427	511	83,702	(83,067)	2,573
Interest expense	(80,620)	(10)	(80,216)	83,067	(77,779)
Loss on repurchases of Chesapeake debt	—	—	(1,353)	—	(1,353)
Equity in net earnings of subsidiaries	—	—	14,075	(14,075)	—
Total Other Income (Expense)	(79,193)	501	16,208	(14,075)	(76,559)
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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2003:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 690,812	$ (47,826)	$ 259,490	$ (248,959)	$ 653,517
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(596,708)	—	(929,348)	—	(1,526,056)
Additions to long-term investments	—	—	(5,750)	—	(5,750)
Investment in Pioneer Drilling	—	—	(20,000)	—	(20,000)
Liquidation proceeds on investment in Seven Seas	—	—	5,333	—	5,333
Additions to other property, plant and equipment and other	(13,073)	(20,731)	(20,491)	—	(54,295)
Cash (used in) provided by investing activities	(609,781)	(20,731)	(970,256)	—	(1,600,768)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	485,000	—	—	—	485,000
Payments on long-term borrowings	(413,000)	—	—	—	(413,000)
Net increase in outstanding payments in excess of cash balances	6,341	—	—	—	6,341
Cash received from issuance of senior notes	—	—	297,306	—	297,306
Cash paid for issuance costs of senior notes	—	—	(6,367)	—	(6,367)
Cash paid for treasury stocks	—	—	(2,109)	—	(2,109)
Proceeds from issuance of common stock, net of issuance costs	—	—	177,444	—	177,444
Proceeds from issuance of preferred stock, net of issuance costs	—	—	222,893	—	222,893
Cash dividends paid on preferred stock and common stock	—	—	(34,551)	—	(34,551)
Cash received from exercise of stock options and warrants	—	—	7,787	—	7,787
Other	(2,403)	—	(249)	—	(2,652)
Intercompany advances, net	(125,200)	82,753	(206,512)	248,959	—
Cash provided by (used in) financing activities	(49,262)	82,753	455,642	248,959	738,092
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	31,769	14,196	(255,124)	—	(209,159)
CASH, BEGINNING OF PERIOD	(31,975)	24,448	255,164	—	247,637
CASH, END OF PERIOD	$ (206)	$ 38,644	$ 40	$ —	$ 38,478

	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)
Additions to other property, plant and equipment and other	(9,313)	(5,282)	(14,676)	—	(29,271)
Other investments, net	—	—	1,807	—	1,807
Cash (used in) provided by investing activities	(306,512)	(5,282)	(305,389)	—	(617,183)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	95,818	—	—	—	95,818
Payments on long-term borrowings	(95,818)	—	—	—	(95,818)
Cash paid for issuance costs of senior notes	—	—	(3,671)	—	(3,671)
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
Other	—	—	(74)	—	(74)
Intercompany advances, net	(25,605)	6,328	5,202	14,075	—
Cash (used in) 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

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

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Parent	Eliminations	Consolidated
For the Three Months Ended September 30, 2003:					
Net income	$ 89,430	$ 899	$ 87,859	$ (90,329)	$ 87,859
Other comprehensive income - net of income tax:					
Change in fair value of derivative instruments	60,551	—	—	—	60,551
Reclassification of loss on settled contracts	(14,032)	—	—	—	(14,032)
Ineffectiveness portion of derivatives qualifying for cash flow hedge accounting	(3,311)	—	—	—	(3,311)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	43,208	(43,208)	—
Comprehensive income	$ 132,638	$ 899	$ 131,067	$ (133,537)	$ 131,067

	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 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 Subsidiaries	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2003:					
Net income	$ 246,516	$ 2,443	$ 243,608	$ (248,959)	$ 243,608
Other comprehensive income - net of income tax:					
Change in fair value of derivative instruments	23,692	—	—	—	23,692
Reclassification of loss on settled contracts	39,320	—	—	—	39,320
Ineffectiveness portion of derivatives qualifying for cash flow hedge accounting	(3,597)	—	—	—	(3,597)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	59,415	(59,415)	—
Comprehensive income	$ 305,931	$ 2,443	$ 303,023	$ (308,374)	$ 303,023

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Nine Months Ended September 30, 2002:					
Net income (loss)	$ 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 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)

6. Segment Information

Chesapeake has two reportable segments under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, consisting of exploration and production, and marketing. The reportable segment information can be derived from Note 5 as Chesapeake Energy Marketing, Inc., Mayfield Processing L.L.C. and MidCon Compression L.P. are the only non-guarantor subsidiaries for all income statement periods presented, and are each involved in the marketing of oil and gas.

7. Recent Accounting Pronouncements

During 2002 and 2003, the Financial Accounting Standards Board issued the following Statements of Financial Accounting Standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In July 2002, the FASB issued SFAS No. 146, *Accounting For Costs Associated with Exit or Disposal Activities*. SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002. We adopted this standard during the quarter ended March 31, 2003 and it did not have any impact on our financial position or results of operations.

In March 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS 149 is effective for contracts entered into or modified after June 30, 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. We adopted this standard during the quarter ended September 30, 2003 and it did not have any impact on our financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity.* SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003 and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This statement establishes new standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability because the financial instrument embodies an obligation of the issuer. This statement applies to certain forms of mandatorily redeemable financial instruments including certain types of preferred stock, written put options and forward contracts. Adoption of this standard did not have any significant impact on our financial position or results of operations.

8. Asset Retirement Obligations

Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed and any gain or loss resulting from the settlement of the obligation is recorded.

We identified and estimated all of our asset retirement obligations for tangible, long-lived assets as of January 1, 2003. These obligations were for future plugging and abandonment costs for depleted oil and gas wells. Prior to the adoption of SFAS 143, we included an estimate of our asset retirement obligations related to our oil and gas properties in our calculation of oil and gas depreciation, depletion and amortization expense. Upon adoption of SFAS 143, we recorded the discounted fair value of our expected future obligations. During the quarter ended March 31, 2003, we recorded a $30.5 million liability, a cumulative effect for the change in accounting principle as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million. The pro-forma effect on prior periods' financial position and results of operations was not material.

The components of the change in our asset retirement obligations are shown below.

	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2003
Asset retirement obligations, beginning balance	$ 44,699	$ 30,479
Additions and revisions	1,328	17,871
Settlements and disposals	(292)	(4,063)
Accretion expense	805	2,253
Asset retirement obligations, ending balance	$ 46,540	$ 46,540

9. Acquisitions and Related Financing

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of ONEOK, Inc. in January 2003 for $296 million, $15 million of which was paid in 2002. In March 2003, we acquired El Paso Corporation's Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million and Vintage Petroleum, Inc.'s assets in the Bray Field in southern Oklahoma for $29 million. We also completed an acquisition of privately-owned Oxley Petroleum Company for $155 million in May 2003. On July 31, 2003, Chesapeake purchased oil and gas properties, a gathering system and a gas treatment plant from a major oil and gas company for $44.5 million.

In March 2003, Chesapeake bought 5.3 million newly issued common shares of Pioneer Drilling Company, or 24.6% of its outstanding common shares, at $3.75 per share, for a total investment of $20 million. This investment has been recorded under the equity method of accounting, whereby we record our proportionate share of the net income or loss of Pioneer Drilling Company.

On March 5, 2003, we issued 23 million shares of common stock pursuant to a shelf registration statement for net proceeds of $177.4 million. We also issued 4.6 million shares of 6.00% cumulative convertible preferred stock with a liquidation value of $230 million. The net proceeds from the preferred stock were $222.9 million. These proceeds, along with the net proceeds of $290.9 million from the issuance of the $300 million in aggregate principal amount of 7.50% senior notes issued at the same time, were used to fund acquisitions completed in March 2003 and to repay credit facility indebtedness. Each share of the 6.00% preferred stock is convertible at any time at the option of the holder into 4.8605 shares of our common stock, subject to adjustment. At September 30, 2003, 41.8 million shares of our common stock were reserved for issuance upon conversion of the 6.00% and 6.75% cumulative convertible preferred stock.

In September 2003, Chesapeake invested $5.8 million in Eagle Energy Partners I, L.P. Chesapeake owns a 25% limited partnership interest, which is accounted for under the equity method.

10. Subsequent Events

On October 3, 2003, we issued an additional $23.7 million of our 7.75% senior notes due 2015 and accrued interest of $0.4 million in exchange for $6.0 million of 8.375% senior notes due 2008 and $0.2 million of accrued interest as well as $16.8 million of 8.125% senior notes due 2011, pursuant to a privately negotiated transaction. The $6.0 million of 8.375% senior notes due 2008 and the $16.8 million of 8.125% senior notes due 2011 were retired upon receipt.

On October 17, 2003, we issued an additional $63.8 million of our 7.50% senior notes due 2013 and accrued interest of $0.4 million in exchange for $54.9 million of our 8.125% senior notes due 2011 and accrued interest of $0.2 million as well as $6.3 million of our 8.375% senior notes due 2008 and accrued interest of $0.2 million, pursuant to a privately negotiated transaction. The $54.9 million of 8.125% senior notes due 2011 and the $6.3 million of 8.375% senior notes due 2008 were retired upon receipt.

On October 31, 2003, Chesapeake purchased approximately $200 million of south Texas natural gas assets from Houston-based privately owned Laredo Energy, L.P. and its partners. We used our revolving bank credit facility to fund the acquisition.

We recently announced a series of transactions intended to improve our capital structure:

Pending Private Offering of Senior Notes. On November 12, 2003, we commenced a private placement of $200 million of senior notes due 2016. The senior notes are being offered only to qualified institutional buyers under Rule 144A of the Securities Act of 1933 and to non-U.S. persons in offshore transactions pursuant to Regulation S under the Securities Act. Net proceeds are expected to be used to fund the tender offer for our 8.5% senior notes due 2012 described below and to repay borrowings under our bank credit facility incurred primarily to finance the Laredo Energy acquisition. There is no assurance the private offering will be completed or, if completed, completed for the amount contemplated. The closing of this offering is not conditioned on the closing of the senior notes offering.

Pending Public Offering of Convertible Preferred Stock. On November 12, 2003, we commenced a public offering of 1,500,000 shares of a new series of our cumulative convertible preferred stock (plus up to 225,000 additional shares subject to the underwriters' overallotment option) at a price of $100 per share offered pursuant to our existing shelf registration statement. Net proceeds to the company will be used, together with a portion of the net proceeds from the private offering of senior notes described above, to repay borrowings on our bank credit facility incurred primarily to finance the Laredo Energy acquisition. There is no assurance this offering will be completed and the completion of this senior notes offering is not conditioned on the closing of the preferred stock offering.

Tender Offer for 8.5% Senior Notes due 2012. On November 12, 2003, we launched a cash tender offer for all approximately $111 million outstanding principal amount of our 8.5% senior notes due 2012. The tender offer is conditioned upon the closing of the private placement of senior notes described above and the receipt of consents to remove substantially all of the restrictive covenants on the 8.5% senior notes from holders of a majority of the outstanding principal amount of the notes. If fully subscribed, it is expected the tender offer will cost approximately $118 million, which would be funded with a portion of the net proceeds from the private placement of senior notes described above. There is no assurance that the tender offer, which is expected to be completed on December 10, 2003, will be subscribed for any amount.

Possible Exchange Offer for 8.125% Senior Notes due 2011. On November 11, 2003, we announced that we are considering making a private exchange offer to certain eligible holders for up to $500 million aggregate principal amount of our 8.125% senior notes due 2011. There is currently approximately $728 million in principal amount of our 8.125% senior notes outstanding. The offer, if made, will be to exchange our 8.125% senior notes due 2011 for notes of one or more series of our senior notes with a final maturity date after 2011, including additional notes of an existing series of our senior notes or additional notes of the new series of senior notes to be offered in our pending private placement, or for a combination thereof. There is no assurance the exchange offer, if commenced, will be subscribed for at any amount.

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,	
	2003	2002	2003	2002
Net Production:				
Oil (mbbl)	1,216	872	3,500	2,525
Gas (mmcf)	63,684	41,429	174,066	116,826
Gas equivalent (mmcfe)	70,980	46,661	195,066	131,976
Oil and Gas Sales ($ in thousands):				
Oil sales	$ 33,908	$ 24,302	$ 101,811	$ 63,017
Oil derivatives – realized gains (losses)	(2,045)	(1,918)	(8,924)	1,176
Oil derivatives – unrealized gains (losses)	185	(1,364)	(993)	(8,180)
Total oil sales	32,048	21,020	91,894	56,013
Gas sales	293,309	116,551	889,598	309,827
Gas derivatives – realized gains (losses)	19,781	24,078	(65,028)	82,973
Gas derivatives – unrealized gains (losses)	449	(7,400)	34,661	(81,003)
Total gas sales	313,539	133,229	859,231	311,797
Total oil and gas sales	$ 345,587	$ 154,249	$ 951,125	$ 367,810
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 27.88	$ 27.87	$ 29.09	$ 24.96
Gas ($ per mcf)	$ 4.61	$ 2.81	$ 5.11	$ 2.65
Gas equivalent ($ per mcfe)	$ 4.61	$ 3.02	$ 5.08	$ 2.83
Average Sales Price (including realized, but excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 26.20	$ 25.67	$ 26.54	$ 25.42
Gas ($ per mcf)	$ 4.92	$ 3.39	$ 4.74	$ 3.36
Gas equivalent ($ per mcfe)	$ 4.86	$ 3.49	$ 4.70	$ 3.46
Expenses ($ per mcfe):				
Production expenses	$ 0.51	$ 0.53	$ 0.52	$ 0.54
Production taxes	$ 0.30	$ 0.15	$ 0.29	$ 0.15
General and administrative	$ 0.08	$ 0.08	$ 0.09	$ 0.09
Depreciation, depletion and amortization	$ 1.38	$ 1.25	$ 1.36	$ 1.20
Net Wells Drilled	130	79	326	204
Net Producing Wells at End of Period	5,710	4,102	5,710	4,102

Significant Developments During Current Period

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of ONEOK, Inc. in January 2003. We paid $296 million in cash for these assets, $15 million of which was paid in late 2002.

On March 5, 2003, we issued 23 million shares of common stock pursuant to a shelf registration statement for net proceeds of $177.4 million. We also issued 4.6 million shares of 6.00% cumulative convertible preferred stock with a liquidation value of $230 million. The net proceeds were $222.9 million.

Also in March 2003, we closed a private offering of $300 million in aggregate principal amount of 7.50% senior notes due 2013. The net proceeds were $290.9 million. These proceeds, along with the net proceeds from the common stock and preferred stock offerings, were used to fund acquisitions completed in March 2003 and to repay credit facility indebtedness.

In March 2003, we acquired El Paso Corporation's Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million.

In March 2003, we acquired Vintage Petroleum, Inc.'s assets in the Bray Field of southern Oklahoma for $29 million.

In May 2003, we acquired privately-owned Oxley Petroleum Company for $155 million. The acquired assets are primarily in the Arkoma Basin, which is located in eastern Oklahoma and western Arkansas.

In July 2003, we acquired oil and gas properties, a gathering system and a gas treatment plant from a major oil and gas company for $44.5 million.

Results of Operations — Three Months Ended September 30, 2003 ("Current Quarter") vs. September 30, 2002 ("Prior Quarter")

General. For the Current Quarter, Chesapeake had net income available to common shareholders of $81.9 million, or $0.33 per diluted common share, on total revenues of $454.5 million. This compares to net income available to common shareholders of $14.1 million, or $0.08 per diluted common share, on total revenues of $196.5 million during the Prior Quarter. The Current Quarter net income includes, on a pre-tax basis, $2.5 million in net unrealized losses on oil and gas and interest rate derivatives. The Prior Quarter net income included, on a pre-tax basis, $7.0 million in net unrealized losses on oil and gas and interest rate derivatives.

Oil and Gas Sales. During the Current Quarter, oil and gas sales were $345.6 million versus $154.2 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 71.0 bcfe at an average price of $4.86 per mcfe, compared to 46.7 bcfe produced in the Prior Quarter at an average price of $3.49 per mcfe (average prices for all periods presented include realized, but exclude unrealized, gains (losses) on derivatives). The increase in realized prices in the Current Quarter resulted in an increase in oil and gas sales of $97.0 million along with an increase of $84.9 million due to increased production, for a net increase in realized oil and gas sales (excluding unrealized gains (losses) on oil and gas derivatives) of $181.9 million. Unrealized gains (losses) included in oil and gas sales in the Current Quarter and Prior Quarter were $0.6 million and $(8.8) million, respectively.

Changes in oil and gas prices have a significant impact on our oil and gas revenues and cash flows. Based upon the Current Quarter production levels, a change of $0.10 per mcf of natural gas would result in a quarterly increase or decrease in revenues and cash flow of approximately $6.4 million and $6.0 million, respectively, without considering the effect of derivatives, and a change of $1.00 per barrel of oil would result in a quarterly increase or decrease in revenues and cash flows of approximately $1.2 million and $1.1 million, respectively, without considering the effect of derivatives.

For the Current Quarter, we realized an average price per barrel of oil of $26.20, compared to $25.67 in the Prior Quarter. Natural gas prices realized per mcf were $4.92 and $3.39 in the Current Quarter and Prior Quarter, respectively (average prices for all periods include realized, but exclude unrealized, gains (losses) on derivatives). Net realized gains from derivatives increased oil and gas revenues from $327.3 million to $345.0 million, an increase of $17.7 million, or $0.25 per mcfe, in the Current Quarter compared to an increase from $140.8 million to $163.0 million, an increase of $22.2 million, or $0.47 per mcfe, in the Prior Quarter.

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

	For the Three Months Ended September 30,			
	2003		2002	
Operating Areas	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	62,909	89%	39,024	84%
Gulf Coast and South Texas	5,266	7	5,074	11
Permian Basin	2,063	3	1,719	3
Williston Basin and Other	742	1	844	2
Total Production	70,980	100%	46,661	100%

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

Oil and Gas Marketing Sales. Chesapeake realized $109.0 million in oil and gas marketing sales for third parties in the Current Quarter, with corresponding oil and gas marketing expenses of $105.8 million, for a net margin of $3.2 million. This compares to sales of $42.2 million and expenses of $41.1 million, for a net margin of $1.1 million in the Prior Quarter. The increased activity in the Current Quarter is primarily the result of an increase in volumes resulting from acquisitions that occurred in late 2002 and the Current Period combined with higher prices received.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $35.9 million in the Current Quarter, a $10.9 million increase from the $25.0 million of production expenses incurred in the Prior Quarter. On a unit of production basis, production expenses were $0.51 and $0.53 per mcfe in the Current and Prior Quarters, respectively. The decrease in costs on a per unit basis in 2003 compared to 2002 is due primarily to lower operating costs associated with properties acquired in 2003. We expect that production expenses per mcfe produced for the remainder of 2003 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $21.6 million and $6.8 million in the Current and Prior Quarters, respectively. On a unit of production basis, production taxes were $0.30 per mcfe in the Current Quarter compared to $0.15 per mcfe in the Prior Quarter. The increase in the Current Quarter of $14.8 million was due to an increase in production volumes of 52% as well as an increase in the average wellhead prices received for natural gas. 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 2003 will range from $0.31 to $0.33 per mcfe based on our assumption that oil and natural gas wellhead prices will range from $4.50 to $5.00 per mcfe produced.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties, were $5.6 million in the Current Quarter compared to $3.8 million in the Prior Quarter. The increase in the Current Quarter is primarily the result of the company's growth related to acquisitions completed during the Current and Prior Period. On a per unit of production basis, general and administrative expenses were $0.08 in both the Current and Prior Quarters. We expect general and administrative expenses for the remainder of 2003 to be between $0.09 and $0.10 per mcfe produced.

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 $9.9 million and $6.2 million of internal costs in the Current Quarter and Prior Quarter, respectively, directly related to our oil and gas exploration and development efforts.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Quarter was $97.9 million, compared to $58.3 million in the Prior Quarter. The average DD&A rate per mcfe, which is a function of capitalized costs, estimated salvage value, future development costs and the related underlying reserves in the periods presented, increased from $1.25 in the Prior Quarter to $1.38 in the Current Quarter. The increase in the average rate in the Current Quarter is primarily the result of higher drilling costs and higher costs associated with acquisitions. We expect the DD&A rate for the remainder of 2003 to be between $1.38 and $1.40 per mcfe produced.

Effective January 1, 2003, Chesapeake adopted SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for a future retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold. This accretion expense is included in DD&A expense on oil and gas properties. In addition, SFAS 143 effectively reduces DD&A rates when compared to prior periods (prior to accretion expense) by including the capitalized retirement obligation at its discounted fair value rather than the undiscounted amount of the estimated liability. During the Current Quarter, accretion expense related to asset retirement obligations was $0.8 million and is included in oil and gas depreciation, depletion and amortization expense.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $4.8 million in the Current Quarter, compared to $3.7 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation costs on recently acquired fixed assets. Other property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 31.5 years, processing plants are depreciated over 15 years, drilling rigs are depreciated over 12 years and all other property and equipment is depreciated over the estimated useful lives of the assets which range from three to seven years. To the extent the drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect depreciation and amortization of other assets to be between $0.08 and $0.10 per mcfe produced for the remainder of 2003.

Interest and Other Income. Interest and other income was a loss of $0.2 million in the Current Quarter compared to a gain of $1.8 million in the Prior Quarter. The decrease in the Current Quarter was the result of a decrease in interest income on outstanding cash balances during the Current Quarter, the recognition of a loss of $0.3 million on our investment in Pioneer Drilling Company and the recognition of interest income of $1.1 million in the Prior Quarter related to our investment in notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $40.9 million in the Current Quarter from $26.6 million in the Prior Quarter. The increase in the Current Quarter is due primarily to a $566.9 million increase in average long-term borrowings in the Current Quarter compared to the Prior Quarter. In addition to the interest expense reported, we capitalized $3.4 million of interest during the Current Quarter, compared to $1.3 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 on our outstanding borrowings. We expect interest expense for the remainder of 2003 to be between $0.55 and $0.60 per mcfe produced based on indebtedness as of September 30, 2003, which is net of interest expected to be capitalized during the period.

From time to time, we enter into derivative instruments designed to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value of interest rate derivatives are recorded on the condensed consolidated balance sheets as assets (liabilities) and the debt's carrying amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense. Interest expense during the Current Quarter included an unrealized loss on interest rate derivatives of $3.1 million and a realized gain on interest rate derivatives of $1.1 million. Interest expense during the Prior Quarter included an unrealized gain on interest rate derivatives of $1.7 million and a realized gain on interest rate derivatives of $1.1 million.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $53.8 million in the Current Quarter, compared to income tax expense of $11.1 million in the Prior Quarter. We anticipate that the effective tax rate for 2003 will be approximately 38% and substantially all 2003 income tax expense will be deferred.

Results of Operations — Nine Months Ended September 30, 2003 ("Current Period") vs. September 30, 2002 ("Prior Period")

General. For the Current Period, Chesapeake had net income available to common shareholders of $228.1 million, or $0.96 per diluted common share, on total revenues of $1,260.7 million. This compares to $6.5 million, or $0.04 per diluted common share, on total revenues of $480.1 million during the Prior Period. The Current Period net income includes, on a pre-tax basis, $28.3 million in net unrealized gains on oil and gas and interest rate derivatives. The Prior Period net income included, on a pre-tax basis, $87.0 million in net unrealized losses on oil and gas and interest rate derivatives.

Oil and Gas Sales. During the Current Period, oil and gas sales were $951.1 million versus $367.8 million in the Prior Period. In the Current Period, Chesapeake produced 195.1 bcfe at an average price of $4.70 per mcfe, compared to 132.0 bcfe produced in the Prior Period at an average price of $3.46 per mcfe (average prices for all periods presented include realized, but exclude unrealized, gains (losses) on derivatives). The increase in prices in the Current Period resulted in an increase in oil and gas sales of $241.9 million along with an increase of $218.6 million due to increased production, for a net increase in oil and gas sales (excluding unrealized gains (losses) on oil and gas derivatives) of $460.5 million. Unrealized gains (losses) included in oil and gas sales in the Current Period and Prior Period were $33.7 million and $(89.2) million, respectively.

Changes in oil and gas prices have a significant impact on our oil and gas revenues and cash flows. Based upon the Current Period production levels, a change of $0.10 per mcf of natural gas would result in an increase or decrease in revenues and cash flow of approximately $17.4 million and $16.3 million, respectively, without considering the effect of derivatives, and a change of $1.00 per barrel of oil would result in an increase or decrease in revenues and cash flows of approximately $3.5 million and $3.3 million, respectively, without considering the effect of derivatives.

For the Current Period, we realized an average price per barrel of oil of $26.54, compared to $25.42 in the Prior Period. Natural gas prices realized per mcf were $4.74 and $3.36 in the Current Period and Prior Period, respectively (average prices for all periods include realized, but exclude unrealized, gains (losses) on derivatives).

Net realized losses from derivatives decreased oil and gas revenues from $991.4 million to $917.4 million, a decrease of $74.0 million, or $0.38 per mcfe, in the Current Period compared to an increase from $372.9 million to $457.0 million, an increase of $84.1 million, or $0.63 per mcfe, in the Prior Period.

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

	For the Nine Months Ended September 30,			
	2003		2002	
Operating Areas	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	170,898	88%	105,996	80%
Gulf Coast and South Texas	15,871	8	18,059	14
Permian Basin	6,049	3	5,524	4
Williston Basin and Other	2,248	1	2,397	2
Total Production	195,066	100%	131,976	100%

Natural gas production represented approximately 89% of our total production volume on an equivalent basis in the Current Period and the Prior Period.

Oil and Gas Marketing Sales. Chesapeake realized $309.6 million in oil and gas marketing sales for third parties in the Current Period, with corresponding oil and gas marketing expenses of $302.1 million, for a net margin of $7.5 million. This compares to sales of $112.3 million and expenses of $108.8 million, for a net margin of $3.5 million in the Prior Period. The increased activity in the Current Period is the result of higher prices received in the Current Period combined with an increase in volumes resulting from acquisitions that occurred in late 2002 and the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $101.7 million in the Current Period, a $30.4 million increase from the $71.3 million of production expenses incurred in the Prior Period. On a unit of production basis, production expenses were $0.52 and $0.54 per mcfe in the Current and Prior Periods, respectively. The decrease in costs on a per unit basis in 2003 compared to 2002 is due primarily to lower operating costs associated with properties acquired in 2003. We expect that production expenses per mcfe produced for the remainder of 2003 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $57.3 million and $19.9 million in the Current and Prior Periods, respectively. On a unit of production basis, production taxes were $0.29 per mcfe in the Current Period compared to $0.15 per mcfe in the Prior Period. The increase in the Current Period of $37.4 million was due to an increase in production volumes of 48% as well as an increase in the average wellhead prices received for natural gas. 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 2003 will range from $0.31 to $0.33 per mcfe based on our assumption that oil and natural gas wellhead prices will range from $4.50 to $5.00 per mcfe produced.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties, were $17.3 million in the Current Period compared to $11.9 million in the Prior Period. The increase in the Current Period is primarily the result of the company's growth related to acquisitions completed during the Current and Prior Period. On a per unit of production basis, general and administrative expenses were $0.09 in both the Current and Prior Period. We expect general and administrative expenses for the remainder of 2003 to be between $0.09 and $0.10 per mcfe produced.

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 $25.7 million and $17.8 million of internal costs in the Current Period and Prior Period, respectively, directly related to our oil and gas exploration and development efforts.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Period was $266.1 million, compared to $157.7 million in the Prior Period. The average DD&A rate per mcfe, which is a function of capitalized costs, estimated salvage value, future development costs and the related underlying reserves in the periods presented, increased from $1.20 in the Prior Period to $1.36 in the Current Period. The increase in the average rate in the Current Period is primarily the result of higher drilling costs and higher costs associated with acquisitions. We expect the DD&A rate for the remainder of 2003 to be between $1.38 and $1.40 per mcfe produced.

Effective January 1, 2003, Chesapeake adopted SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold. This accretion expense is included in DD&A expense on oil and gas properties. In addition, SFAS 143 effectively reduces DD&A rates when compared to prior periods (prior to accretion expense) by including the capitalized retirement obligation at its discounted fair value rather than the undiscounted amount of the estimated liability. During the Current Period, accretion expense related to asset retirement obligations was $2.3 million and is included in oil and gas depreciation, depletion and amortization expense.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $12.6 million in the Current Period, compared to $10.5 million in the Prior Period. The increase in the Current Period was primarily the result of higher depreciation costs on recently acquired fixed assets. Other property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 31.5 years, processing plants are depreciated over 15 years, drilling rigs are depreciated over 12 years and all other property and equipment is depreciated over the estimated useful lives of the assets which range from three to seven years. To the extent the drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect depreciation and amortization of other assets to be between $0.08 and $0.10 per mcfe produced for the remainder of 2003.

Interest and Other Income. Interest and other income was $1.4 million in the Current Period compared to $7.3 million in the Prior Period. The decrease in the Current Period was the result of a $1.9 million decrease in interest income on outstanding cash balances during the Current Period and the recognition of $3.0 million of interest income in the Prior Period related to our investment in notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $115.9 million in the Current Period from $77.8 million in the Prior Period. The increase in the Current Period is due to a $529.0 million increase in average long-term borrowings in the Current Period compared to the Prior Period. In addition to the interest expense reported, we capitalized $8.8 million of interest during the Current Period, compared to $3.6 million capitalized in the Prior Period, 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 on our outstanding borrowings. We expect interest expense for the remainder of 2003 to be between $0.55 and $0.60 per mcfe produced based on indebtedness as of September 30, 2003, which is net of interest expected to be capitalized during the period.

From time to time, we enter into derivative instruments designed to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value of interest rate derivatives are recorded on the condensed consolidated balance sheets as assets (liabilities) and the debt's carrying amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense. Interest expense during the Current Period included an unrealized loss on interest rate derivatives of $5.3 million and a realized gain on interest rate derivatives of $2.5 million. Interest expense during the Prior Period included an unrealized gain on interest rate derivatives of $2.2 million and a realized gain on interest rate derivatives of $2.7 million.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $147.8 million in the Current Period, compared to $9.4 million in the Prior Period. We anticipate that the effective tax rate for 2003 will be approximately 38% and substantially all 2003 income tax expense will be deferred.

Cash Flows From Operating, Investing and Financing Activities

Cash Flows from Operating Activities. Cash provided by operating activities increased 85% to $653.5 million during the Current Period compared to $353.7 million during the Prior Period. The increase was due primarily to an increase in oil and gas realized prices and an increase in gas sales volume in the Current Period.

Cash Flows from Investing Activities. Cash used in investing activities increased to $1,600.8 million during the Current Period from $617.2 million in the Prior Period. During the Current Period, we expended approximately $501.9 million to drill 751 (326 net) wells and invested approximately $130.4 million in unproved properties. This compares to $252.8 million to initiate drilling on 517 (204 net) wells and $46.8 million to purchase unproved properties in the Prior Period. During the Current Period, we completed acquisitions of proved oil and gas properties of $909.5 million and completed $21.2 million of divestitures of proved oil and gas properties. This compares to cash used in acquisitions of proved oil and gas properties of $291.4 million and $1.2 million of divestitures in the Prior Period. During the Current Period, we had additional investments in a processing plant, drilling rig equipment and other fixed assets of $59.8 million compared to investments in other fixed assets of $29.3 million in the Prior Period. The Current Period included an investment of $20.0 million in the common stock of Pioneer Drilling Company (AMEX: PDC) and a $5.8 million equity investment in Eagle Energy Partners I, L.P., a newly formed gas marketing company. We received $5.3 million in liquidation proceeds from our investment in Seven Seas Petroleum Inc. during the Current Period.

Cash Flows from Financing Activities. Cash flows from financing activities were $738.1 million in the Current Period, compared to $171.3 million in the Prior Period. During the Current Period, we borrowed $485.0 million under our bank credit facility and made repayments under this facility of $413.0 million. In the Current Period, we received $297.3 million from the issuance of $300 million principal amount of our 7.50% senior notes and paid $6.4 million in costs related to the issuance of these notes. We issued 23 million shares of common stock and received $177.4 million of net proceeds. We issued 4.6 million shares of 6.00% cumulative convertible preferred stock, $50 per share liquidation preference, or $230 million in the aggregate, and received $222.9 million of net proceeds. During the Current Period, we used $19.7 million to pay common stock dividends, $7.6 million to pay dividends on our 6.75% preferred stock, $7.3 million to pay dividends on our 6.00% preferred stock and $2.1 million to purchase treasury stock. We received $7.8 million from the exercise of stock options and warrants, and we had $6.3 million of outstanding payments in excess of our funded cash balances as of September 30, 2003. The activity in the Prior Period included borrowings under our bank credit facility of $95.8 million and repayments under this facility of $95.8 million. We repurchased $63.5 million of our 7.875% senior notes. We received $246.0 million from the issuance of $250 million of 9.00% senior notes and $2.1 million cash from the exercise of stock options. We used $3.7 million to pay financing costs and $7.6 million to pay dividends on our 6.75% preferred stock.

Liquidity and Capital Resources

Sources of Liquidity

Chesapeake had a working capital deficit of $49.4 million at September 30, 2003, including $38.5 million in cash. Another source of liquidity is our $350 million revolving bank credit facility (see discussion below).

We believe we will have adequate resources, including budgeted cash flows from operating activities before changes in assets and liabilities, working capital and proceeds from our revolving bank credit facility, to fund our exploration and development activities during the remainder of 2003 and 2004. Our capital expenditure budget for drilling, land and seismic data for the remainder of 2003 is estimated to be between $175 million and $200 million. However, higher drilling and field operating costs, unfavorable drilling results or other factors could cause us to reduce our drilling program, which is largely discretionary. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes.

A significant portion of our liquidity at September 30, 2003 is concentrated in cash and cash equivalents and derivative instruments. Financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments, equity securities and accounts receivable. 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 industry concentration 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 are not a commercial paper issuer.

Contractual Obligations

We have a $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. As of September 30, 2003, we had $72.0 million of outstanding borrowings under this facility and utilized $10.3 million of the facility for 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 our senior unsecured long-term debt ratings issued by Standard & Poor's Ratings Services and Moody's Investor Service. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee also based on our senior unsecured long-term debt ratings. Interest is payable quarterly.

The credit agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans or purchase certain of our senior notes, and create liens. The credit agreement requires us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio for the trailing twelve month period (as defined) of at least 2.5 to 1. At September 30, 2003, our current ratio was 1.5 to 1 and our fixed charge coverage ratio was 4.4 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. Such acceleration, if involving a principal amount of $10.0 million or more, 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 agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $25.0 million.

As of September 30, 2003, senior notes represented approximately $2.0 billion of our long-term debt and consisted of the following ($ in thousands):

7.875% senior notes, due 2004	$ 42,137[1]
8.375% senior notes, due 2008	222,150
8.125% senior notes, due 2011	800,000
8.500% senior notes, due 2012	110,669
9.000% senior notes, due 2012	300,000
7.500% senior notes, due 2013	300,000
7.750% senior notes, due 2015	213,001
	$1,987,957

(1) This amount has been classified as long-term debt based on our ability to satisfy this obligation with funding from our bank credit facility.

There are no scheduled principal payments required on any of the senior notes until March 2004, when $42.1 million is due. Debt ratings for the senior notes are Ba3 by Moody's Investor Service, BB- by Standard & Poor's Ratings Services and BB- by Fitch Ratings as of November 3, 2003. Debt ratings for our secured bank credit facility are Ba2 by Moody's Investor Service, BBB- 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 our marketing subsidiaries guarantee the notes. The indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures for the 8.125%, 8.375%, 9.000%, 7.750% and 7.500% 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, 2003, we estimate that secured commercial bank indebtedness of approximately $882 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., Mayfield Processing L.L.C. and MidCon Compression L.P., which are our only unrestricted subsidiaries.

Some of our commodity price and financial risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price and financial risk management transactions exceed certain levels. At September 30, 2003, we were required to post $8.0 million of collateral which we provided by a letter of credit under our credit facility. Future collateral requirements are uncertain and will depend on arrangements with our counterparties, highly volatile natural gas and oil prices and fluctuations in interest rates.

Investing and Financing Transactions

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of ONEOK, Inc. in January 2003. We paid $296 million in cash for these assets, $15 million of which was paid in late 2002.

On March 5, 2003, we closed a private offering of $300 million in aggregate principal amount of senior notes, issued 23 million shares of common stock pursuant to a shelf registration statement and issued $230 million liquidation amount of convertible preferred stock in a private placement. Net proceeds from these transactions were used to finance the acquisition of oil and gas properties from El Paso Corporation and Vintage Petroleum, Inc. as discussed below and to repay indebtedness under our bank credit facility.

In March 2003, we acquired El Paso Corporation’s Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million.

In March 2003, we acquired Vintage Petroleum, Inc.’s assets in the Bray field in southern Oklahoma for $29 million.

In March 2003, Chesapeake bought 5.3 million newly issued common shares of Pioneer Drilling Company, or 24.6% of its outstanding common shares, at $3.75 per share, for a total investment of $20 million.

In May 2003, we acquired privately-owned Oxley Petroleum Company for $155 million. The acquired assets are primarily in the Arkoma Basin which is located in eastern Oklahoma and western Arkansas.

On July 16, 2003, we issued an additional $29.5 million of our 7.75% senior notes due 2015 in exchange for $27.9 million of our 8.375% senior notes due 2008 and $0.5 million of accrued interest, pursuant to a privately negotiated transaction. The $27.9 million of 8.375% senior notes due 2008 were promptly retired upon receipt.

In July 2003, we acquired oil and gas properties, a gathering system and a gas treatment plant from a major oil and gas company for $44.5 million.

On August 5, 2003, we issued an additional $33.5 million of our 7.75% senior notes due 2015 and accrued interest of $0.1 million in exchange for $32.0 million of our 8.5% senior notes due 2012 and $1.1 million of accrued interest, pursuant to a privately negotiated transaction. The $32.0 million of 8.5% senior notes were retired upon receipt.

In September 2003, Chesapeake invested $5.8 million in Eagle Energy Partners I, L.P., a newly formed gas marketing company. Chesapeake owns a 25% limited partnership interest, which is accounted for under the equity method.

On October 3, 2003, we issued an additional $23.7 million of our 7.75% senior notes due 2015 and accrued interest of $0.4 million in exchange for $6.0 million of 8.375% senior notes due 2008 and $0.2 million of accrued interest as well as $16.8 million of 8.125% senior notes due 2011, pursuant to a privately negotiated transaction. The $6.0 million of 8.375% senior notes due 2008 and the $16.8 million of 8.125% senior notes due 2011 were retired upon receipt.

On October 17, 2003, we issued an additional $63.8 million of our 7.50% senior notes due 2013 and accrued interest of $0.4 million in exchange for $54.9 million of our 8.125% senior notes due 2011 and accrued interest of $0.2 million as well as $6.3 million of our 8.375% senior notes due 2008 and accrued interest of $0.2 million, pursuant to a privately negotiated transaction. The $54.9 million of 8.125% senior notes due 2011 and the $6.3 million of 8.375% senior notes due 2008 were retired upon receipt.

On October 31, 2003, Chesapeake purchased approximately $200 million of south Texas natural gas assets from Houston-based privately owned Laredo Energy, L.P. and its partners. We used our revolving bank credit facility to fund the acquisition.

Contingencies

Royalty owners have commenced litigation against a number of oil and gas producers claiming that amounts paid for production attributable to the royalty owners’ interest violated the terms of applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the leases, and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. Typically this litigation has taken the form of class action suits. There are presently four such suits filed against Chesapeake, two in Texas and two in Oklahoma. No class has been certified in any of them. In one of the Oklahoma cases, we determined that a portion of the marketing fee we had charged royalty owners should be refunded. We have deposited with the court the aggregate amount of the fees we estimated should be refunded, $3.6 million, in an interest-bearing account for distribution to affected royalty owners. This amount has been charged to general and administrative expenses, of which $0.3 million was charged in the Current Period and the remainder was recorded in 2002. We do not believe any other claims made by royalty owners in the cases pending against us are valid. Even if the claims were upheld, we believe any damages awarded would not be material. This is a developing area of the law, however, and as new cases are decided, our potential liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor 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.

Critical Accounting Policies

We consider accounting policies related to stock options, hedging, oil and gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K/A for the year ended December 31, 2002, except for our accounting policy related to stock options which is summarized in Note 1 of the notes to the consolidated financial statements included in our annual report on Form 10-K/A.

Statement of Financial Accounting Standards No. 141, *Business Combinations* and Statement of Financial Accounting Standards No. 142, *Goodwill and Intangible Assets* were issued by the Financial Accounting Standards Board in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment.

One interpretation being considered relative to these standards is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties as intangible assets on our condensed consolidated balance sheets. In addition, the disclosures required by SFAS 141 and 142 relative to intangibles would be included in the notes to the condensed consolidated financial statements. Historically, we, like many other oil and gas companies, have included these rights as part of oil and gas properties, even after SFAS 141 and 142 became effective.

As it applies to companies like us that have adopted full cost accounting for oil and gas activities, we understand that this interpretation of SFAS 141 and 142 would only affect our balance sheet classification of proved oil and gas leaseholds acquired after June 30, 2001 and all of our unproved oil and gas leaseholds. We would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because we did not separately value or account for these costs prior to the adoption date of SFAS 141. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and gas reserves would continue to be amortized in accordance with full cost accounting rules.

As of September 30, 2003 and December 31, 2002, we had undeveloped leaseholds of approximately $175.3 million and $72.5 million, respectively, that would be classified on our condensed consolidated balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $1,495.5 million and $581.9 million, respectively, that would be classified as "intangible developed leasehold" if we applied the interpretation discussed above.

We will continue to classify our oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as oil and gas properties until further guidance is provided.

Recently Issued Accounting Standards

See Note 7 of the notes to the condensed 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 estimates of oil and gas reserves, expected oil and gas production and future expenditures, planned capital expenditures for drilling, leasehold acquisitions and seismic data, and statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning 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 2002 Form 10-K/A and subsequent filings with the Securities and Exchange Commission. These factors include:

- the volatility of oil and gas prices,
- adverse effects our substantial indebtedness could have on our operating and future growth,
- our ability to compete effectively against strong independent oil and gas companies and majors,
- the cost and availability of drilling and production services,
- possible financial losses as a result of our commodity price and interest rate risk management activities,
- uncertainties inherent in estimating quantities of oil and gas reserves, including reserves we acquire, projecting future rates of production and the timing of development expenditures,
- exposure to potential liabilities of acquired properties,
- our ability to replace reserves,
- the availability of capital,
- changes in interest rates, and
- drilling and operating risks.

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.

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, 2003, our oil and gas derivative instruments were comprised of swaps, cap-swaps 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, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays 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.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written option does not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.
- Basis protection swaps are arrangements that guarantee a price differential of oil or 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.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap or cap-swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap's designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets, to the extent that a legal right of setoff exists.

Gains or losses from the oil and gas derivative transactions are reflected as adjustments to oil and gas sales on the condensed consolidated statement of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales were $0.6 million, $(8.8) million, $33.7 million and $(89.2) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. Amounts relating to ineffectiveness on cash flow hedges consisted of a gain of $5.3 million in the Current Quarter, a loss of $0.1 million in the Prior Quarter, a gain of $5.8 million in the Current Period and a loss of $2.2 million in the Prior Period.

As of September 30, 2003, we had the following open oil and natural gas derivative instruments designed to hedge a portion of our oil and natural gas production for periods after September 2003:

	Volume mmbtu/bbls	Weighted-Average Strike Price	Weighted-Average Put Strike Price	Weighted Average Differential to NYMEX	Qualifies As SFAS 133 Hedge	Fair Value at September 30, 2003 (in thousands)
Natural Gas:						
Swaps:						
2003	42,020,000	5.73	—	—	Yes	$ 40,190
2004	65,450,000	5.42	—	—	Yes	34,439
2005	40,150,000	4.79	—	—	Yes	5,466
2006	25,550,000	4.74	—	—	Yes	5,878
2007	25,550,000	4.76	—	—	Yes	6,345
	198,720,000					
Cap-Swaps:						
2003	12,880,000	3.69	2.69	—	No	(14,077)
2004	3,660,000	5.00	3.50	—	No	(643)
	16,540,000					
Counter-Swaps:						
2003	(12,880,000)	3.84	—	—	No	12,070
Basis Protection Swaps:						
2003	41,400,000	—	—	(0.19)	No	164
2004	157,380,000	—	—	(0.17)	No	7,849
2005	109,500,000	—	—	(0.16)	No	8,389
2006	47,450,000	—	—	(0.16)	No	2,897
2007	63,875,000	—	—	(0.17)	No	3,547
2008	64,050,000	—	—	(0.17)	No	3,251
2009	36,500,000	—	—	(0.16)	No	2,029
	520,155,000					
Locked Swaps:						
2003	—	—	—	—	No	375
2004	—	—	—	—	No	2,302
Total Natural Gas						120,471
Oil:						
Cap-Swaps:						
2003	1,040,000	28.30	21.44	—	No	(761)
2004	3,878,000	28.31	21.71	—	No	(2,484)
	4,918,000					
Total Oil						(3,245)
Total Natural Gas and Oil						$ 117,226

We have established the fair value of all derivative instruments first using estimates of fair value reported by our counterparties and subsequently by using established index prices and other sources. 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, 2003.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows:

	2003 ($ in thousands)
Fair value of contracts outstanding at January 1	$ (14,533)
Change in fair value of contracts during the period	57,807
Contracts realized or otherwise settled during the period	73,952
Fair value of new contracts when entered into during the period	—
Fair value of contracts outstanding at September 30	$ 117,226

Based upon the market prices at September 30, 2003, we expect to transfer approximately $44.3 million of the gain included in accumulated other comprehensive income to earnings during the next 12 months when the hedged oil or gas production is sold. All transactions hedged as of September 30, 2003 are for periods extending through 2007, with the exception of the basis protection swaps which extend to 2009.

Derivative instruments reflected as current in the condensed consolidated balance sheets 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 date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

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 July 2002, we closed two interest rate swaps for a cash settlement of $8.6 million. As of September 30, 2003, the remaining balance to be amortized as a reduction to interest expense was $0.3 million. During the Current Quarter and Current Period, $0.1 million and $0.4 million, respectively, were recorded as a reduction to interest expense.

On August 13, 2003, we entered into an interest rate swap having the following terms:

Term	Notional Amount	Fixed Rate	Floating Rate
August 2003 – August 2005	$100,000,000	2.735%	U.S. six-month LIBOR in arrears

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. Payments under this interest rate swap will be made on February 15 and August 15 of each year beginning February 15, 2004. At September 30, 2003, this interest rate swap had a fair value of $1.2 million.

On August 22, 2003, we entered into an additional interest rate swap having the following terms:

Term	Notional Amount	Fixed Rate	Floating Rate
August 2003 – August 2005	$100,000,000	3.000%	U.S. six-month LIBOR in arrears

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. Payments under this interest rate swap will be made on February 27 and August 27 of each year beginning February 27, 2004. At September 30, 2003, this interest rate swap had a fair value of $1.6 million.

In March 1997, Chesapeake issued $150.0 million of 8.5% senior notes due 2012, of which $7.3 million were subsequently repurchased and retired. The 8.5% senior notes include a “call option” whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. This call option, also referred to as a right of optional redemption, allows Chesapeake to redeem the notes prior to their stated maturity date beginning in March 2004. This right of optional redemption has value depending upon changes in interest rates. Due to a decline in interest rates, Chesapeake effectively sold this optional redemption right to an unrelated third party (or counterparty) for $7.8 million in April 2002. In exchange for the $7.8 million, Chesapeake gave the counterparty the option to elect whether or not to enter into an interest rate swap with Chesapeake on March 11, 2004. This transaction is more commonly referred to as a swaption. The terms of the interest rate swap, if executed by the counterparty, would be 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

The interest rate swap would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap on March 11, 2004, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

This transaction does not alter Chesapeake’s ability to redeem the 8.5% senior notes. Instead, it locks-in the economics of a future call. If interest rates are high and the swaption is not “in-the-money”, the counterparty will likely not elect to enter into the interest rate swap, the swaption will expire, and Chesapeake will amortize the $7.8 million premium as a reduction to interest expense over the remaining life of the notes. If interest rates are low and the swaption is "in-the-money", the counterparty will likely exercise the swaption and force Chesapeake to settle the transaction at the then current value of the interest rate swap, and Chesapeake will amortize both the $7.8 million premium and the amount paid to the counterparty to interest expense over the remaining life of the notes. If Chesapeake elects to refinance the 8.5% senior notes, any unamortized premium or loss remaining related to the swaption would be included in the gain (or loss) on the early extinguishment of debt.

According to SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and the swaption agreement. The fair value of the swaption is recorded on the condensed consolidated balance sheets as a liability, and the debt's carrying amount is adjusted by the change in the fair value of the call option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense.

During the Current Quarter, we exchanged and subsequently retired $32.0 million of our 8.5% senior notes. In connection with this retirement, we have removed the designation of the corresponding portion of the swaption agreement as a fair value hedge in accordance with SFAS 133. We recorded a $3.3 million increase to the fair value of the debt to reflect the portion of the 8.5% senior notes exchanged and subsequently retired in the Current Quarter. Temporary fluctuations in the fair value of the portion of the swaption no longer designated as a fair value hedge are recorded as adjustments to interest expense. We recorded a $2.0 million unrealized loss in interest expense during the Current Quarter due to a decline in the fair value of the portion of the swaption no longer designated as a fair value hedge.

We recorded an adjustment to the carrying amount of the debt of $15.4 million as of September 30, 2003 which represents the temporary fluctuations in the fair value of the call option included in senior notes. Since the inception of the swaption, we have recorded a change in the fair market value of the swaption from a $7.8 million liability to a $33.8 million liability, an increase of $26.0 million. After giving effect to the removal of the designation of a portion of the swaption as a fair value hedge under SFAS 133 as described previously, the difference of $5.3 million represents ineffectiveness which has been recorded as additional interest expense.

Interest Rate Risk

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, 2003							
	Years of Maturity							
	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt, including current portion — fixed rate....	$ 42.1	$ —	$ —	$ —	$222.2	$1,723.7	$1,988.0(1)	$ 2,129.9
Average interest rate	7.9%	—	—	—	8.4%	8.1%	8.2%	8.2%
Long-term debt — variable rate	$ —	$ —	$ —	$ 72.0	$ —	$ —	$ 72.0	$ 72.0
Average interest rate	—	—	—	4.23%	—	—	4.23%	4.23%

(1) This amount does not include the discount of $(22.8) million, the value of the interest rate swaps of $2.6 million and the value of the swaption of $(15.4) million, which are all included in long-tem debt on the condensed consolidated balance sheet.

ITEM 4. *Controls and Procedures*

Our Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of September 30, 2003, have concluded the company's disclosure controls and procedures are effective. No changes in the company's internal control over financial reporting occurred during the current quarter that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

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.

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
4.1.1	Fourteenth Supplemental Indenture dated as of August 15, 2003 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.
4.2.1	Fourteenth Supplemental Indenture dated as of August 15, 2003 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.
4.3.1	Ninth Supplemental Indenture dated as of August 15, 2003 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.
4.4.1	Sixth Supplemental Indenture dated as of August 15, 2003 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, as Trustee, with respect to 8.375% Senior Notes due 2008.
4.5.1	Third Supplemental Indenture dated August 15, 2003 to Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 9.0% Senior Notes due 2012.
4.6.1	Third Supplemental Indenture dated as of August 15, 2003 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as

	Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.75% Senior Notes due 2015.
4.7.1	Second Supplemental Indenture dated as of August 15, 2003 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 7.5% Senior Notes due 2013.
10.2.3	Employment Agreement dated as of July 1, 2003 between Marcus C. Rowland and Chesapeake Energy Corporation.
10.2.8	Employment Agreement dated as of July 1, 2003 between Michael A. Johnson and Chesapeake Energy Corporation.
10.2.9	Employment Agreement dated as of July 1, 2003 between Martha A. Burger and Chesapeake Energy Corporation.
12	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
21	Subsidiaries of Chesapeake.
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Furnished as provided in Item 601 of Regulation S-K.

(b) *Reports on Form 8-K*

During the quarter ended September 30, 2003, we filed the following current reports on Form 8-K:

On July 29, 2003, we filed a current report on Form 8-K, furnishing under Item 12 a press release we issued on July 28, 2003 announcing financial and operating results for the second quarter 2003 and updated 2003 and 2004 guidance.

On September 22, 2003 we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on September 19, 2003 announcing the declaration of common and preferred stock dividends.

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 12, 2003

INDEX TO EXHIBITS

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* Furnished as provided in Item 601 of Regulation S-K.

Exhibit 31.1

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

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

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

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

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

(c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

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

Date: November 12, 2003

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

Exhibit 31.2

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

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

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

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

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

(c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

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

Date: November 12, 2003

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

Exhibit 32.1

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

In connection with the Quarterly Report of Chesapeake Energy Corporation (the “Company”) on Form 10-Q for the period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, 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 12, 2003

Exhibit 32.2

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

In connection with the Quarterly Report of Chesapeake Energy Corporation (the "Company") on Form 10-Q for the period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, 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 12, 2003