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 June 30, 2002

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

For the transition period from   to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

At July 31, 2002, there were 166,122,358 shares of our $.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	December 31, 2001	June 30, 2002
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 117,594	$ 6,296
Restricted cash	7,366	131
Accounts receivable:		
Oil and gas sales	51,496	84,352
Joint interest, net of allowances of $947,000 and $1,093,000, respectively	17,364	23,073
Short-term derivatives	34,543	16,069
Related parties	9,896	7,250
Other	14,951	17,877
Short-term derivative instruments	97,544	12,509
Inventory and other	10,629	10,522
Total Current Assets	361,383	178,079
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	3,546,163	3,920,587
Unevaluated properties	66,205	59,907
Less: accumulated depreciation, depletion and amortization	(1,902,587)	(2,001,984)
	1,709,781	1,978,510
Other property and equipment	115,694	132,522
Less: accumulated depreciation and amortization	(39,894)	(42,466)
Total Property and Equipment	1,785,581	2,068,566
OTHER ASSETS:		
Long-term derivatives receivable	18,852	8,351
Deferred income tax asset	67,781	35,405
Long-term derivative instruments	6,370	515
Long-term investments	29,849	25,089
Other assets	16,952	14,223
Total Other Assets	139,804	83,583
TOTAL ASSETS	$ 2,286,768	$ 2,330,228
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Notes payable and current maturities of long-term debt	$ 602	$ 154
Accounts payable	79,945	80,871
Accrued interest	26,316	26,023
Short-term derivative instruments	—	461
Other accrued liabilities	36,998	53,557
Revenues and royalties due others	29,520	36,592
Total Current Liabilities	173,381	197,658
LONG-TERM DEBT, NET	1,329,453	1,326,351
REVENUES AND ROYALTIES DUE OTHERS	12,696	12,948
LONG-TERM DERIVATIVE INSTRUMENTS	—	52,016
OTHER LIABILITIES	3,831	7,833
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 10,000,000 shares authorized; 3,000,000 shares and 2,998,000 of 6.75% cumulative convertible preferred stock, issued and outstanding at December 31, 2001 and June 30, 2002, respectively, entitled in liquidation to $150 million and $149.9 million	150,000	149,900
Common Stock, $.01 par value, 350,000,000 shares authorized, 169,534,991 and 170,911,163 shares issued at December 31, 2001 and June 30, 2002, respectively	1,696	1,709
Paid-in capital	1,035,156	1,038,889
Accumulated deficit	(442,974)	(453,173)
Accumulated other comprehensive income, net of tax of $29,000,000 and $10,719,000, respectively	43,511	16,079
Less: treasury stock, at cost; 4,792,529 common shares at December 31, 2001 and June 30, 2002	(19,982)	(19,982)
Total Stockholders' Equity	767,407	733,422
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,286,768	$ 2,330,228

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2002	2001	2002
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 175,225	$ 152,009	$ 396,444	$ 293,980
Risk management income (loss)	62,455	(481)	62,455	(79,949)
Oil and gas marketing sales	38,001	42,785	94,166	70,118
Total Revenues	275,681	194,313	553,065	284,149
OPERATING COSTS:				
Production expenses	18,842	24,242	36,630	46,302
Production taxes	9,991	7,911	24,286	13,127
General and administrative	2,873	3,859	6,874	8,153
Oil and gas marketing expenses	36,913	41,181	91,391	67,688
Oil and gas depreciation, depletion and amortization	39,910	50,778	78,083	99,397
Depreciation and amortization of other assets	1,837	3,652	3,790	6,762
Total Operating Costs	110,366	131,623	241,054	241,429
INCOME FROM OPERATIONS	165,315	62,690	312,011	42,720
OTHER INCOME (EXPENSE):				
Interest and other income	683	3,719	1,252	4,673
Interest expense	(22,984)	(24,690)	(48,873)	(51,650)
Gothic standby credit facility costs	—	—	(3,392)	—
Total Other Income (Expense)	(22,301)	(20,971)	(51,013)	(46,977)
INCOME (LOSS) BEFORE INCOME TAX	143,014	41,719	260,998	(4,257)
PROVISION (BENEFIT) FOR INCOME TAXES	57,529	16,686	105,225	(1,704)
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	85,485	25,033	155,773	(2,553)
EXTRAORDINARY ITEM:				
Loss on early extinguishment of debt, net of applicable income tax	(46,000)	—	(46,000)	—
NET INCOME (LOSS)	39,485	25,033	109,773	(2,553)
PREFERED STOCK DIVIDENDS	(182)	(2,530)	(728)	(5,062)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 39,303	$ 22,503	$ 109,045	$ (7,615)
EARNINGS (LOSS) PER COMMON SHARE — BASIC:				
Income before extraordinary item	$ 0.52	$ 0.14	$ 0.97	$ (0.05)
Extraordinary item	(0.28)	—	(0.29)	—
Net income (loss)	$ 0.24	$ 0.14	$ 0.68	$ (0.05)
EARNINGS (LOSS) PER COMMON SHARE — ASSUMING DILUTION:				
Income before extraordinary item	$ 0.50	$ 0.13	$ 0.91	$ (0.05)
Extraordinary item	(0.27)	—	(0.27)	—
Net income (loss)	$ 0.23	$ 0.13	$ 0.64	$ (0.05)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING :				
Basic	162,588	165,963	160,161	165,669
Assuming dilution	171,321	191,947	170,835	165,669

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2001	Six Months Ended June 30, 2002
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ 109,773	$ (2,553)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	80,088	103,770
Risk management (income) loss	(62,455)	79,949
Extraordinary loss on early-extinguishment of debt	46,000	—
Deferred income taxes	105,225	(1,702)
Write-off of credit facility cost	3,392	—
Amortization of loan costs	1,785	2,389
Amortization of bond discount	349	510
Accretion of Gothic note premium	(750)	—
Loss on sale/disposal of fixed assets and other	29	36
Equity in losses (earnings) of equity investees	260	—
Loss on repurchase of debt	—	864
Gain on sale of RAM Energy notes	—	(461)
Bad debt expense	—	140
Other	85	(412)
Cash provided by operating activities before changes in assets and liabilities	283,781	182,530
Changes in assets and liabilities	13,221	32,295
Cash provided by operating activities	297,002	214,825
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of oil and gas properties	(179,864)	(176,386)
Acquisition of unproved properties	(48,533)	(7,167)
Acquisition of oil and gas companies and proved properties, net of cash acquired	(53,103)	(124,305)
Sales of oil and gas properties	174	—
Sales of non-oil and gas assets	159	62
Additions to buildings and other fixed assets	(8,834)	(16,066)
Additions to drilling rig equipment	(11,930)	(2,506)
Additions to long-term investments	(591)	(2,408)
Proceeds from sale of RAM Energy notes	—	4,215
Other	480	(11)
Cash used in investing activities	(302,042)	(324,572)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving bank credit facility	273,000	45,000
Payments on revolving bank credit facility	(138,000)	—
Cash received from issuance of senior notes	786,664	—
Cash paid to repurchase senior notes	(830,382)	(42,201)
Cash paid for premium on repurchase of senior notes	(75,639)	(1,019)
Cash paid for financing costs related to debt	(12,214)	(95)
Cash received from exercise of stock options	2,782	1,956
Cash paid for preferred stock dividend	(1,092)	(5,118)
Other	(11)	(74)
Cash provided by (used in) financing activities	5,108	(1,551)
Effect of changes in exchange rate on cash	(68)	—
NET CHANGE IN CASH AND CASH EQUIVALENTS	—	(111,298)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	117,594
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ 6,296

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2002	2001	2002
	($ in thousands)			
Net income (loss)	$ 39,485	$ 25,033	$ 109,773	$ (2,553)
Other comprehensive income (loss), net of income tax:				
Foreign currency translation adjustments	2,494	—	(725)	—
Cumulative effect of accounting change for financial derivatives	—	—	(53,580)	—
Change in fair value of derivative instruments	53,331	(2,242)	95,469	(12,972)
Reclassification of (gain) or loss on settled contracts	(2,314)	(1,683)	16,012	(15,769)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(576)	815	(576)	1,309
Comprehensive income (loss)	$ 92,420	$ 21,923	$ 166,373	$ (29,985)

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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

1. Basis of Presentation and 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 six months ended June 30, 2002 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2001 (the "Prior Quarter" and "Prior Period", respectively) and the three and six months ended June 30, 2002 (the "Current Quarter" and "Current Period", respectively).

2. Hedging Activities and Financial Instruments

Oil and Gas Hedging Activities

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

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

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

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

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

	June 30, 2002
	($ in thousands)
Derivative assets (liabilities):	
Fixed-price gas swaps	$ (1,486)
Fixed-price gas collars	4,206
Fixed-price gas cap-swaps	10,025
Gas basis protection swaps	(6,116)
Gas straddles	(9,506)
Gas strangles	(29,278)
Fixed-price gas counter-swaps	6,239
Fixed-price gas locked swaps	24,224
Fixed-price crude oil swaps	(19)
Fixed-price crude oil cap-swaps	(1,779)
Fixed-price crude oil locked swaps	196
Estimated fair value	$ (3,294)
Estimated fair value, as adjusted for premiums received	$ 31,170(a)

(a) After adjusting for the $34.5 million premium paid to Chesapeake by the counterparty at the inception of the straddle and strangle contracts (which is recorded in cash provided by operating activities on the accompanying consolidated statements of cash flows), the net value of the combined hedging portfolio at June 30, 2002 was $31.2 million.

Based upon the market prices at June 30, 2002, we would expect to transfer approximately $11.3 million of the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of June 30, 2002 are expected to mature by December 31, 2004, with the exception of the basis protection swaps which extend to 2009.

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

Fair value of contracts outstanding at January 1, 2002	$ 157,309
Change in fair value of contracts during period	(55,623)
Contracts realized or otherwise settled during the period	(61,989)
Fair value of new contracts when entered into during the period	(42,991)
Fair value of contracts outstanding at June 30, 2002	$ (3,294)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2002	2001	2002
Risk management income (loss):				
Change in fair value of derivatives not qualifying for hedge accounting	$ 61,495	$ 10,884	$ 61,495	$ (42,530)
Reclassification of gain on settled contracts	—	(10,630)	—	(35,707)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	960	(1,358)	960	(2,182)
Total	$ 62,455	$ (1,104)	$ 62,455	$ (80,419)

Interest Rate Risk

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

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

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 the interest rate swap coincide with the semi-annual interest payments on our 7.875% senior notes which are due September 15 and March 15 of each year beginning September 15, 2002.

A portion of the interest rate swap was originally entered into to convert $129.0 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of this interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge under which the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in the carrying value of the debt. See Note 5 of the notes to consolidated financial statements included in this report for the adjustments made to the carrying value of the debt at June 30, 2002. During the Current Quarter, $21.2 million of the 7.875% senior notes were purchased and subsequently retired resulting in a $0.4 million gain on the repurchase of the debt related to the interest rate swap. As a result of these repurchases, $107.8 million of the interest rate swap was designated as a fair value hedge under SFAS 133 at June 30, 2002.

Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the swap agreement.

The remaining $92.2 million of the interest rate swap has not been designated as a fair value hedge. The mark-to-market value of this portion of the instrument is recorded as a derivative asset or liability on the consolidated balance sheets with the offsetting amount reflected in risk management income (loss) on the consolidated statements of operations. The amount recorded in risk management income (loss) will be reversed and reflected in interest expense over the term of the swap.

The estimated fair value of the interest rate swap at June 30, 2002 was an asset of approximately $5.0 million comprised of $1.6 million reflected as risk management income, $1.4 million reflected as an increase in the carrying value of the long-term debt, $1.6 million reflected as a reduction in interest expense and $0.4 reflected as other income related to the gain on the repurchase of debt.

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

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

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 are made on July 2 and January 2 of each year beginning January 2, 2003. The estimated fair value of the interest rate swap at June 30, 2002 was negligible.

In July 2002, we closed both interest rate swaps for a combined gain of $8.6 million. Gains totaling $6.6 million, in addition to the $2.0 million gain already realized in the Current Quarter, will be recognized as reductions to interest expense over the remaining terms of the swaps.

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

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

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

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

We have recorded a decrease in the carrying value of the debt of $7.8 million related to the swaption as of June 30, 2002. Of this amount, $8.9 million represents the mark-to-market valuation of the swaption offset by $1.1 million of estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 5 of the notes to consolidated financial statements included in this report for the adjustments made to the carrying value of the debt at June 30, 2002. Results of the swaption will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

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

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002
Risk management income:		
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 2,454	$ 2,301
Reclassification of gain on settled contracts	(731)	(731)
Ineffective portion of derivatives qualifying for fair value hedge accounting	(1,100)	(1,100)
Total	$ 623	$ 470

Fair Value of Financial Instruments

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

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term (including current maturities), fixed-rate debt using primarily quoted market prices. Excluding the impact of our fair value hedges, our carrying amount for such debt at December 31, 2001 and June 30, 2002 was $1,330.1 million and $1,287.9 million, respectively, compared to approximate fair values of $1,343.0 and $1,297.3 million, respectively. The carrying value of other long-term debt, which consists of amounts outstanding under our revolving bank credit facility, approximates its fair value as interest rates on the facility are based on prevailing market rates. The carrying amount for our 6.75% convertible preferred stock at June 30, 2002 was $149.9 million, compared to the approximate fair value of $173.9 million.

Concentration of Credit Risk

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

3. Contingencies and Commitments

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

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

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

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

Royalty Owner Litigation. Recently royalty owners have commenced litigation against a number of companies in the oil and gas production business claiming that amounts paid for production attributable to the royalty owners' interest violated the terms of the applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the applicable leases and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. In the course of our oil and gas marketing activities, a portion of the foregoing litigation has been commenced as class action suits including four class action suits filed against Chesapeake and others which we believe do not represent valid claims or, if valid, are not material. As new cases are decided and the law in this area continues to develop, our liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor the court decisions to ensure that our operations and practices minimize any exposure and to recognize any charges that may be appropriate.

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

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

4. Net Income Per Share

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

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

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

- For the Prior Quarter, the Current Quarter, the Prior Period and the Current Period, outstanding options to purchase 0.3 million, 0.3 million, 0.2 million and 0.4 million shares of common stock at a weighted average exercise price of $15.98, $15.30, $18.78 and $14.44, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.

- As a result of the Current Period's net loss to common shareholders, the diluted shares do not include the effect of outstanding stock options to purchase 5.9 million shares of common stock at a weighted average exercise price of $3.90, the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares), the common stock equivalent of preferred stock outstanding prior to conversion (11,480 shares) or warrants to purchase 6,574 shares of common stock at a weighted average exercise price of $0.05 as the effects were antidilutive.

A reconciliation for the three months ended June 30, 2001 and 2002 and the six months ended June 30, 2001 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Three Months Ended June 30, 2001:			
Basic EPS			
Income available to common shareholders	$ 39,303	162,588	$ 0.24
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of Preferred shares exchanged during the period:			
Common shares issued	—	1,432	
Preferred stock dividends	182	—	
Employee stock options	—	7,294	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 39,485	171,321	$ 0.23

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Three Months Ended June 30, 2002:			
Basic EPS			
Income available to common shareholders	$ 22,503	165,963	$ 0.14
Effect of Dilutive Securities			
Preferred stock dividends	2,530	—	
Assumed conversion of 6.75% preferred stock at beginning of period	—	19,478	
Employee stock options	—	6,500	
Warrants assumed in Gothic acquisition	—	6	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 25,033	191,947	$ 0.13

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Six Months Ended June 30, 2001:			
Basic EPS			
Income available to common shareholders	$ 109,045	160,161	$ 0.68
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:			
Common shares issued	—	2,952	
Preferred stock dividends	728	—	
Employee stock options	—	7,715	
Warrants assumed in Gothic acquisition	—	7	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 109,773	170,835	$ 0.64

In a private offering on November 13, 2001 we issued 3.0 million shares of 6.75% cumulative convertible preferred stock at a par value $0.01 per share with a liquidation preference of $50 per share. We subsequently registered the shares of the preferred stock and the underlying common stock for resale under the Securities Act of 1933.

5. Senior Notes and Revolving Credit Facility

At June 30, 2002, our long-term debt, net of current maturities, consisted of the following ($ in thousands):

7.875% senior notes, due 2004	$ 107,799
8.375% senior notes, due 2008	250,000
8.125% senior notes, due 2011	800,000
8.5% senior notes, due 2012	142,665
Revolving bank credit facility	45,000
Discount on senior notes	(12,697)
Discount for interest rate swap and swaption	(6,416)
Total	$1,326,351

During the Current Period, we purchased and subsequently retired $42.2 million of the 7.875% senior notes for total consideration of $44.0 million, including $0.8 million of accrued interest and $1.0 million of redemption premium.

We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of June 30, 2002, we had borrowed $45.0 million under this facility and were using $11.1 million of the facility to secure various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically. The maturity of the bank credit facility can be extended at our option to June 2005 if we satisfy certain conditions.

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

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

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under the 8.375% senior notes, the 8.125% senior notes, the 7.875% senior notes and the 8.5% senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by each of our "restricted subsidiaries" (as defined in the respective indentures governing these notes) (collectively, the "guarantor subsidiaries"). Each guarantor subsidiary is a direct or indirect wholly-owned subsidiary.

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

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

	Guarantor Subsidiary	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (7,905)	$ 19,714	$ 113,151	$ —	$ 124,960
Accounts receivable	113,493	30,380	2,715	(18,338)	128,250
Short-term derivative instruments	97,544	—	—	—	97,544
Inventory and other	10,208	421	—	—	10,629
Total Current Assets	213,340	50,515	115,866	(18,338)	361,383
PROPERTY AND EQUIPMENT:					
Oil and gas properties	3,546,163	—	—	—	3,546,163
Unevaluated leasehold	66,205	—	—	—	66,205
Other property and equipment	53,681	23,537	38,476	—	115,694
Less: accumulated depreciation, depletion and amortization	(1,920,613)	(18,668)	(3,200)	—	(1,942,481)
Net Property and Equipment	1,745,436	4,869	35,276	—	1,785,581
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	(21,054)	21,054	—
Long-term derivative receivable	18,852	—	—	—	18,852
Deferred income tax asset	(218,596)	(1,376)	287,753	—	67,781
Long-term derivative instruments	6,370	—	—	—	6,370
Long-term investments	—	—	29,849	—	29,849
Other assets	5,589	334	11,050	(21)	16,952
Total Other Assets	(187,785)	(1,042)	307,598	21,033	139,804
TOTAL ASSETS	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 602	$ —	$ —	$ —	$ 602
Accounts payable and other current liabilities	127,967	36,755	26,338	(18,281)	172,779
Total Current Liabilities	128,569	36,755	26,338	(18,281)	173,381
LONG-TERM DEBT	—	—	1,329,453	—	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	12,696	—	—	—	12,696
OTHER LIABILITIES	3,831	—	—	—	3,831
INTERCOMPANY PAYABLES	1,664,517	19	(1,664,458)	(78)	—
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	66	1	1,686	(57)	1,696
Other	(38,688)	17,567	765,721	21,111	765,711
Total Stockholders' Equity (Deficit)	(38,622)	17,568	767,407	21,054	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768

CONDENSED CONSOLIDATED BALANCE SHEET
AS OF JUNE 30, 2002
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 382	$ 6,043	$ 2	$ —	$ 6,427
Accounts receivable	100,967	54,915	5,610	(28,940)	132,552
Short-term derivative accounts receivable	16,069	—	—	—	16,069
Short-term derivative instruments	8,033	—	4,476	—	12,509
Inventory and other	9,829	683	10	—	10,522
Total Current Assets	135,280	61,641	10,098	(28,940)	178,079
PROPERTY AND EQUIPMENT:					
Oil and gas properties	3,920,587	—	—	—	3,920,587
Unevaluated leasehold	59,907	—	—	—	59,907
Other property and equipment	58,441	26,929	47,152	—	132,522
Less: accumulated depreciation, depletion and amortization	(2,021,415)	(19,293)	(3,742)	—	(2,044,450)
Net Property and Equipment	2,017,520	7,636	43,410	—	2,068,566
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	—	—	232,526	(232,526)	—
Long-term derivative receivable	8,351	—	—	—	8,351
Deferred income tax asset	(91,989)	(1,764)	129,158	—	35,405
Long-term investments	—	—	25,089	—	25,089
Long-term derivative instruments	—	—	515	—	515
Other assets	3,992	193	10,064	(26)	14,223
Total Other Assets	(79,646)	(1,571)	397,352	(232,552)	83,583
TOTAL ASSETS	$ 2,073,154	$ 67,706	$ 450,860	$ (261,492)	$ 2,330,228
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 154	$ —	$ —	$ —	$ 154
Accounts payable and other current liabilities	148,270	46,154	31,562	(28,943)	197,043
Short-term derivative instruments	461	—	—	—	461
Total Current Liabilities	148,885	46,154	31,562	(28,943)	197,658
LONG-TERM DEBT	45,000	—	1,281,351	—	1,326,351
REVENUES AND ROYALTIES DUE OTHERS	12,948	—	—	—	12,948
LONG-TERM DERIVATIVE INSTRUMENTS	35,285	—	16,731	—	52,016
OTHER LIABILITIES	7,833	—	—	—	7,833
INTERCOMPANY PAYABLES	1,613,348	(1,119)	(1,612,206)	(23)	—
STOCKHOLDERS' EQUITY:					
Common Stock	66	1	1,699	(57)	1,709
Other	209,789	22,670	731,723	(232,469)	731,713
Total Stockholders' Equity	209,855	22,671	733,422	(232,526)	733,422
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,073,154	$ 67,706	$ 450,860	$ (261,492)	$ 2,330,228

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2001:					
REVENUES:					
Oil and gas sales	$ 175,225	$ —	$ —	$ —	$ 175,225
Risk management income	62,455	—	—	—	62,455
Oil and gas marketing sales	—	108,600	—	(70,599)	38,001
Total Revenues	237,680	108,600	—	(70,599)	275,681
OPERATING COSTS:					
Production expenses and taxes	28,833	—	—	—	28,833
General and administrative	2,550	259	64	—	2,873
Oil and gas marketing expenses	—	107,512	—	(70,599)	36,913
Oil and gas depreciation, depletion and amortization	39,910	—	—	—	39,910
Other depreciation and amortization	1,287	20	530	—	1,837
Total Operating Costs	72,580	107,791	594	(70,599)	110,366
INCOME (LOSS) FROM OPERATIONS	165,100	809	(594)	—	165,315
OTHER INCOME (EXPENSE):					
Interest and other income	697	(101)	23,808	(23,721)	683
Interest expense	(24,201)	—	(22,504)	23,721	(22,984)
Equity in net earnings of subsidiaries	—	—	76,888	(76,888)	—
Total Other Income (Expense)	(23,504)	(101)	78,192	(76,888)	(22,301)
INCOME BEFORE INCOME TAXES AND EXTRAORIDINARY ITEMS	141,596	708	77,598	(76,888)	143,014
INCOME TAX EXPENSE	56,961	284	284	—	57,529
NET INCOME BEFORE EXTRAORDINARY ITEMS	84,635	424	77,314	(76,888)	85,485
EXTRA ORDINARY ITEMS:					
Loss on early extinguishment of debt, net of applicable income tax	(8,171)	—	(37,829)	—	(46,000)
NET INCOME	$ 76,464	$ 424	$ 39,485	$ (76,888)	$ 39,485

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2002:					
REVENUES:					
Oil and gas sales	$ 152,009	$ —	$ —	$ —	$ 152,009
Risk management income (loss)	(1,103)	—	622	—	(481)
Oil and gas marketing sales	—	138,964	—	(96,179)	42,785
Total Revenues	150,906	138,964	622	(96,179)	194,313
OPERATING COSTS:					
Production expenses and taxes	32,153	—	—	—	32,153
General and administrative	3,365	441	53	—	3,859
Oil and gas marketing expenses	—	137,360	—	(96,179)	41,181
Oil and gas depreciation, depletion and amortization	50,778	—	—	—	50,778
Other depreciation and amortization	2,484	493	675	—	3,652
Total Operating Costs	88,780	138,294	728	(96,179)	131,623
INCOME (LOSS) FROM OPERATIONS	62,126	670	(106)	—	62,690
OTHER INCOME (EXPENSE):					
Interest and other income	943	112	29,702	(27,038)	3,719
Interest expense	(26,061)	(8)	(25,659)	27,038	(24,690)
Equity in net earnings of subsidiaries	—	—	22,671	(22,671)	—
Total Other Income (Expense)	(25,118)	104	26,714	(22,671)	(20,971)
INCOME BEFORE INCOME TAXES	37,008	774	26,608	(22,671)	41,719
INCOME TAX EXPENSE	14,802	309	1,575	—	16,686
NET INCOME	$ 22,206	$ 465	$ 25,033	$ (22,671)	$ 25,033

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2001:					
REVENUES:					
Oil and gas sales	$ 396,444	$ —	$ —	$ —	$ 396,444
Risk management income	62,455	—	—	—	62,455
Oil and gas marketing sales	—	242,513	—	(148,347)	94,166
Total Revenues	458,899	242,513	—	(148,347)	553,065
OPERATING COSTS:					
Production expenses and taxes	60,916	—	—	—	60,916
General and administrative	6,093	609	172	—	6,874
Oil and gas marketing expenses	—	239,738	—	(148,347)	91,391
Oil and gas depreciation, depletion and amortization	78,083	—	—	—	78,083
Other depreciation and amortization	2,349	40	1,401	—	3,790
Total Operating Costs	147,441	240,387	1,573	(148,347)	241,054
INCOME (LOSS) FROM OPERATIONS	311,458	2,126	(1,573)	—	312,011
OTHER INCOME (EXPENSE):					
Interest and other income	1,139	(26)	46,542	(46,403)	1,252
Interest expense	(52,015)	(1)	(43,260)	46,403	(48,873)
Gothic standby credit facility costs	—	—	(3,392)	—	(3,392)
Equity in net earnings of subsidiaries	—	—	148,612	(148,612)	—
Total Other Income (Expense)	(50,876)	(27)	148,502	(148,612)	(51,013)
INCOME BEFORE INCOME TAXES AND EXTRAORDINARY ITEMS	260,582	2,099	146,929	(148,612)	260,998
INCOME TAX EXPENSE	105,058	840	(673)	—	105,225
NET INCOME BEFORE EXTRAORDINARY ITEMS	155,524	1,259	147,602	(148,612)	155,773
EXTRAORDINARY ITEMS:					
Loss on early extinguishment of debt, net of applicable income tax	(8,171)	—	(37,829)	—	(46,000)
NET INCOME	$ 147,353	$ 1,259	$ 109,773	$ (148,612)	$ 109,773

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2002:					
REVENUES:					
Oil and gas sales	$ 293,980	$ —	$ —	$ —	$ 293,980
Risk management income (loss)	(80,418)	—	469	—	(79,949)
Oil and gas marketing sales	—	228,429	—	(158,311)	70,118
Total Revenues	213,562	228,429	469	(158,311)	284,149
OPERATING COSTS:					
Production expenses and taxes	59,429	—	—	—	59,429
General and administrative	6,995	892	266	—	8,153
Oil and gas marketing expenses	—	225,999	—	(158,311)	67,688
Oil and gas depreciation, depletion and amortization	99,397	—	—	—	99,397
Other depreciation and amortization	4,655	770	1,337	—	6,762
Total Operating Costs	170,476	227,661	1,603	(158,311)	241,429
INCOME (LOSS) FROM OPERATIONS	43,086	768	(1,134)	—	42,720
OTHER INCOME (EXPENSE):					
Interest and other income	1,152	211	57,817	(54,507)	4,673
Interest expense	(52,630)	(8)	(53,519)	54,507	(51,650)
Equity in net earnings of subsidiaries	—	—	(4,451)	4,451	—
Total Other Income (Expense)	(51,478)	203	(153)	4,451	(46,977)
INCOME (LOSS) BEFORE INCOME TAXES	(8,392)	971	(1,287)	4,451	(4,257)
INCOME TAX EXPENSE (BENEFIT)	(3,358)	388	1,266	—	(1,704)
NET INCOME (LOSS)	$ (5,034)	$ 583	$ (2,553)	$ 4,451	$ (2,553)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2001:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 286,797	$ 5,219	$ 94,153	$ (89,167)	$ 297,002
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(281,326)	—	—	—	(281,326)
Proceeds from sale of assets	159	—	—	—	159
Additions to other property and equipment	(14,712)	(425)	(5,627)	—	(20,764)
Other additions	480	—	(591)	—	(111)
Cash (used in) provided by investing activities	(295,399)	(425)	(6,218)	—	(302,042)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving bank credit facility	273,000	—	—	—	273,000
Payments on revolving bank credit facility	(138,000)	—	—	—	(138,000)
Cash paid for financing costs related to debt	(5,636)	—	(6,578)	—	(12,214)
Cash dividends paid on preferred stock	—	—	(1,092)	—	(1,092)
Cash paid for repurchase of senior notes	—	—	(830,382)	—	(830,382)
Cash paid for repurchase premium on senior notes	—	—	(75,639)	—	(75,639)
Cash received on issuance of senior notes	—	—	786,664	—	786,664
Exercise of stock options	—	—	2,782	—	2,782
Other	—	—	(11)	—	(11)
Intercompany advances, net	(124,937)	(9,819)	45,589	89,167	—
Cash (used in) provided by financing activities	4,427	(9,819)	(78,667)	89,167	5,108
Effect of exchange rate changes on cash	(68)	—	—	—	(68)
NET INCREASE (DECREASE) IN CASH	(4,243)	(5,025)	9,268	—	—
CASH, BEGINNING OF PERIOD	(19,868)	7,200	12,668	—	—
CASH, END OF PERIOD	$ (24,111)	$ 2,175	$ 21,936	$ —	$ —

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2002:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 213,416	$ (13,657)	$ 10,615	$ 4,451	$ 214,825
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(180,607)	—	(127,251)	—	(307,858)
Proceeds from sale of assets	62	—	—	—	62
Additions to other property, plant and equipment and other	(6,499)	(3,408)	(8,676)	—	(18,583)
Other investments, net	—	—	1,807	—	1,807
Cash (used in) provided by investing activities	(187,044)	(3,408)	(134,120)	—	(324,572)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving bank credit facility	45,000	—	—	—	45,000
Cash paid for financing costs related to debt	—	—	(95)	—	(95)
Cash paid for repurchase of senior notes	—	—	(42,201)	—	(42,201)
Cash paid for repurchase premium on senior notes	—	—	(1,019)	—	(1,019)
Cash dividends paid on preferred stock	—	—	(5,118)	—	(5,118)
Exercise of stock options	—	—	1,956	—	1,956
Other	—	—	(74)	—	(74)
Intercompany advances, net	(59,808)	3,394	60,865	(4,451)	—
Cash (used in) provided by financing activities	(14,808)	3,394	14,314	(4,451)	(1,551)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	11,564	(13,671)	(109,191)	—	(111,298)
CASH, BEGINNING OF PERIOD	(11,313)	19,714	109,193	—	117,594
CASH, END OF PERIOD	$ 251	$ 6,043	$ 2	$ —	$ 6,296

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

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2001:					
Net income	$ 76,464	$ 424	$ 8,730	$ (46,133)	$ 39,485
Other comprehensive income, net of income tax:					
Foreign currency translation	2,494	—	—	—	2,494
Change in fair value of derivative instruments	53,331	—	—	—	53,331
Reclassification of gain on settled contracts	(2,314)	—	—	—	(2,314)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(576)	—	—	—	(576)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	83,690	(83,690)	—
Comprehensive income	$ 129,399	$ 424	$ 92,420	$ (129,823)	$ 92,420

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2002:					
Net income	$ 22,206	$ 465	$ 25,033	$ (22,671)	$ 25,033
Other comprehensive income (loss), net of income tax:					
Change in fair value of derivative instruments	(2,242)	—	—	—	(2,242)
Reclassification of gain on settled contracts	(1,683)	—	—	—	(1,683)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	815	—	—	—	815
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(3,110)	3,110	—
Comprehensive income	$ 19,096	$ 465	$ 21,923	$ (19,561)	$ 21,923

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2001:					
Net income	$ 147,353	$ 1,259	$ 50,328	$ (89,167)	$ 109,773
Other comprehensive income (loss), net of income tax:					
Foreign currency translation	(725)	—	—	—	(725)
Cumulative effect of accounting change for financial derivatives	(53,580)	—	—	—	(53,580)
Change in fair value of derivative instruments	95,469	—	—	—	95,469
Reclassification of (gain) or loss on settled contracts	16,012	—	—	—	16,012
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(576)	—	—	—	(576)
Equity in net other comprehensive income (loss) of subsidiaries	—	—	116,045	(116,045)	—
Comprehensive income	$ 203,953	$ 1,259	$ 166,373	$ (205,212)	$ 166,373

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2002:					
Net income (loss)	$ (5,034)	$ 583	$ (2,553)	$ 4,451	$ (2,553)
Other comprehensive income (loss), net of income tax:					
Change in fair value of derivative instruments	(12,972)	—	—	—	(12,972)
Reclassification of gain on settled contracts	(15,769)	—	—	—	(15,769)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	1,309	—	—	—	1,309
Equity in net other comprehensive income (loss) of subsidiaries	—	—	(27,432)	27,432	—
Comprehensive income (loss)	$ (32,466)	$ 583	$ (29,985)	$ 31,883	$ (29,985)

6. Segment Information

Chesapeake has two reportable segments under SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*. One segment relates to our exploration and production activities, and the other segment relates to oil and gas marketing activities. The reportable segment information can be derived from Note 5 as Chesapeake Energy Marketing, Inc., is the only significant non-guarantor subsidiary and the only entity conducting marketing activities for all income statement periods presented.

7. Acquisitions

On June 28, 2002, we acquired Canaan Energy Corporation in a cash merger through a Chesapeake subsidiary. Under the agreement, all outstanding common shares of Canaan, other than the Canaan shares already owned by Chesapeake, were purchased at $18.00 per share in cash, and the outstanding options to acquire Canaan common stock were converted into the right to receive, for each share of Canaan common stock to be received upon exercise, the merger consideration less the per share exercise price and withholding taxes. The aggregate net cash consideration for the merger was $120 million, including the retirement of Canaan's outstanding indebtedness of approximately $43 million.

8. Recent Accounting Pronouncements

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

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

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

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. We have not yet adopted SFAS No. 145 nor have we determined the effect of the adoption on our financial position or results of operations.

In July 2002, the FASB issued SFAS No. 146, *Accounting For Costs Associated with Exit or Disposal Activities*. SFAS No. 146 is effective for exit or disposal activities initiated after December 31, 2002. We have not yet adopted SFAS No. 146 nor determined the effect of the adoption of SFAS No. 146 on our financial position or results of operations.

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 June 30,		Six Months Ended June 30,	
	2001	2002	2001	2002
Net Production:				
Oil (mbbl)	682	823	1,368	1,653
Gas (mmcf)	35,045	38,464	71,085	75,397
Gas equivalent (mmcfe)	39,137	43,402	79,293	85,315
Oil and Gas Sales ($ in thousands):				
Oil	$ 18,893	$ 21,851	$ 38,797	$ 41,809
Gas	156,332	130,158	357,647	252,171
Total oil and gas sales	$ 175,225	$ 152,009	$ 396,444	$ 293,980
Average Sales Price:				
Oil ($ per bbl)	$ 27.70	$ 26.55	$ 28.36	$ 25.29
Gas ($ per mcf)	$ 4.46	$ 3.38	$ 5.03	$ 3.34
Gas equivalent ($ per mcfe)	$ 4.48	$ 3.50	$ 5.00	$ 3.45
Expenses ($ per mcfe):				
Production expenses and taxes	$ 0.74	$ 0.74	$ 0.77	$ 0.69
General and administrative	$ 0.07	$ 0.09	$ 0.09	$ 0.10
Depreciation, depletion and amortization	$ 1.02	$ 1.17	$ 0.98	$ 1.17
Net Wells Drilled	62	67	143	124
Net Wells at End of Period	3,420	3,862	3,420	3,862

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

General. For the Current Quarter, Chesapeake had net income available to common shareholders of $22.5 million, or $0.13 per diluted common share, on total revenues of $194.3 million. This compares to net income available to common shareholders of $39.3 million, or $0.23 per diluted common share, on total revenues of $275.7 million during the Prior Quarter. The Current Quarter's results included, on a pre-tax basis, a non-cash $0.5 million risk management loss, while the Prior Quarter's results included, on a pre-tax basis, non-cash risk management income of $62.5 million.

Oil and Gas Sales. During the Current Quarter, oil and gas sales decreased 13% to $152.0 million from $175.2 million in the Prior Quarter. For the Current Quarter, we produced 43.4 billion cubic feet equivalent (bcfe), consisting of 0.8 million barrels of oil (mmbbl) and 38.5 billion cubic feet of gas (bcf), compared to 0.7 mmbbl and 35.0 bcf, or 39.1 bcfe, in the Prior Quarter. The production increase is primarily the result of successful drilling results complemented with production from various acquisitions which occurred in late 2001, partially offset by the sale of our Canadian reserves effective October 1, 2001. Average oil prices realized were $26.55 per bbl in the Current Quarter compared to $27.70 per bbl in the Prior Quarter, a decrease of 4%. Average gas prices realized were $3.38 per thousand cubic feet in the Current Quarter compared to $4.46 per mcf in the Prior Quarter, a decrease of 24%.

For the Current Quarter, we realized an average price of $3.50 per mcfe, compared to $4.48 per mcfe in the Prior Quarter, including in each case the effects of hedging. Our hedging activities resulted in increased oil and gas revenues of $13.4 million, or $0.31 per mcfe, in the Current Quarter, compared to an increase in oil and gas revenues of $7.2 million, or $0.18 per mcfe, in the Prior Quarter.

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

	For the Three Months Ended June 30,			
	2001		2002	
Operating Areas	(Mmcfe)	Percent	(Mmcfe)	Percent
Mid-Continent	27,045	69%	35,171	81%
Gulf Coast	6,634	17	5,725	13
Permian Basin	1,133	3	1,747	4
Other areas	1,214	3	759	2
Canada	3,111	8	—	—
Total	39,137	100%	43,402	100%

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

Risk Management Income (Loss). Chesapeake recognized a $0.5 million non-cash risk management loss in the Current Quarter, compared to a $62.5 million non-cash gain in the Prior Quarter. The risk management loss for the Current Quarter consisted of a $10.9 million non-cash gain related to changes in fair value of derivatives not designated as cash flow hedges, $10.6 million of reclassifications related to the settlement of such contracts, a $1.4 million non-cash loss associated with the ineffective portion of derivatives qualifying for cash flow hedge accounting, a $1.7 million non-cash gain associated with the portion of our interest rate swap that does not qualify for fair value hedge accounting, and a $1.1 million non-cash loss associated with the ineffective portion of our swaption. Risk management income in the Prior Quarter included a $61.5 million non-cash gain attributable to the change in fair value of certain derivatives not designated as cash flow hedges and a non-cash gain of $1.0 million associated with the ineffective portion of our cash flow hedges.

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

Oil and Gas Marketing Sales. We generated $42.8 million in oil and gas marketing sales for third parties in the Current Quarter, with corresponding oil and gas marketing expenses of $41.2 million, for a net margin of $1.6 million. This compares to sales of $38.0 million, expenses of $36.9 million, and a net margin of $1.1 million in the Prior Quarter. The increase in marketing sales and cost of sales was due primarily to an increase in oil and gas sales volumes in the Current Quarter compared to the Prior Quarter, partially offset by a decrease in oil and gas prices in the Current Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, increased to $24.2 million in the Current Quarter, a $5.4 million increase from the $18.8 million of production expenses incurred in the Prior Quarter. On a unit of production basis, production expenses were $0.56 and $0.48 per mcfe in the Current and Prior Quarters, respectively. The increase in costs on a per unit basis in the Current Quarter is due primarily to increased field service costs, higher production costs associated with properties acquired in 2001 and an increase in ad valorem taxes. We expect that lease operating expenses per mcfe for the remainder of 2002 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $7.9 million and $10.0 million in the Current and Prior Quarters, respectively. On a per unit basis, production taxes were $0.18 per mcfe in the Current Quarter compared to $0.26 per mcfe in the Prior Quarter. The decrease in the Current Quarter was the result of decreased prices and new statutory exemptions on certain wells in Oklahoma and Texas. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes for the remainder of 2002 to be approximately 6% - 7% of oil and gas sales revenues excluding any impact from hedging.

General and Administrative. General and administrative expenses, which are net of capitalized internal costs, were $3.9 million in the Current Quarter compared to $2.9 million in the Prior Quarter. The increase in the Current Quarter is the result of Chesapeake's continued growth.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $2.8 million and $2.1 million of internal costs in the Current Quarter and Prior Quarter, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for the remainder of 2002 will be between $0.10 and $0.11 per mcfe, which is approximately the same level as 2001 and the Current Quarter.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Quarter was $50.8 million, compared to $39.9 million in the Prior Quarter. The DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, increased from $1.02 in the Prior Quarter to $1.17 per mcfe in the Current Quarter. We expect the DD&A rate for the remainder of 2002 to be between $1.25 and $1.35 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $3.7 million in the Current Quarter, compared to $1.8 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation recorded on recently acquired fixed assets. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from three to seven years. We expect depreciation and amortization of other assets to average between $0.08 and $0.10 per mcfe for the remainder of 2002 which approximates the current rate.

Interest and Other Income. Interest and other income for the Current Quarter was $3.7 million compared to $0.7 million in the Prior Quarter. The increase was primarily the result of additional interest income from significantly higher cash balances held during the Current Quarter, as well as interest income recorded on our investment in senior secured notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $24.7 million in the Current Quarter from $23.0 million in the Prior Quarter. The increase in the Current Quarter was due primarily to a $113 million increase in average long-term borrowings in the Current Quarter compared to the Prior Quarter, partially offset by income of $1.6 million earned on our interest rate swap during the Current Quarter. In addition to the interest expense reported, we capitalized $1.1 million of interest during the Current Quarter, compared to $1.4 million capitalized in the Prior Quarter, on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate of our outstanding borrowings. We anticipate that capitalized interest for the remainder of 2002 will be between $2.0 million and $2.5 million.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $16.7 million in the Current Quarter, compared to income tax expense of $57.5 million in the Prior Quarter. Income tax expense for the Prior Quarter was comprised of $54.7 million related to our domestic operations and $2.8 million related to our Canadian operations which were sold on October 1, 2001. We anticipate that all 2002 income tax expense will be deferred.

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

General. For the Current Period, Chesapeake had a net loss available to common shareholders of $7.6 million, or a loss of $0.05 per diluted common share, on total revenues of $284.1 million. This compares to net income available to common shareholders of $109.0 million, or $0.64 per diluted common share, on total revenues of $553.1 million during the Prior Period. The Current Period's net loss included, on a pre-tax basis, a non-cash $79.9 million risk management loss, while the Prior Period's results included, on a pre-tax basis, non-cash risk management income of $62.5 million.

Oil and Gas Sales. During the Current Period, oil and gas sales decreased 26% to $294.0 million from $396.4 million in the Prior Period. For the Current Period, we produced 85.3 billion cubic feet equivalent, consisting of 1.7 million barrels of oil and 75.4 billion cubic feet of gas, compared to 1.4 mmbbl and 71.1 bcf, or 79.3 bcfe, in the Prior Period. The production increase is primarily the result of successful drilling results complemented with production from various acquisitions which occurred in late 2001, partially offset by the sale of our Canadian reserves effective October 1, 2001. Average oil prices realized were $25.29 per bbl in the Current Period compared to $28.36 per bbl in the Prior Period, a decrease of 11%. Average gas prices realized were $3.34 per thousand cubic feet in the Current Period compared to $5.03 per mcf in the Prior Period, a decrease of 34%.

For the Current Period, we realized an average price of $3.45 per mcfe, compared to $5.00 per mcfe in the Prior Period, including in each case the effects of hedging. Our hedging activities resulted in increased oil and gas revenues of $62.0 million, or $0.73 per mcfe, in the Current Period, compared to decreases in oil and gas revenues of $23.3 million, or $0.29 per mcfe, in the Prior Period.

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

	For the Six Months Ended June 30,			
	2001		2002	
Operating Areas	**(Mmcfe)**	**Percent**	**(Mmcfe)**	**Percent**
Mid-Continent	54,030	68%	66,972	79%
Gulf Coast	14,926	19	12,985	15
Permian Basin	2,672	4	3,804	4
Other areas	1,867	2	1,554	2
Canada	5,798	7	—	—
Total	79,293	100%	85,315	100%

Gas production represented approximately 88% of our total production volume on an equivalent basis in the Current Period, compared to 90% in the Prior Period.

Risk Management Income (Loss). Chesapeake recognized a $79.9 million non-cash risk management loss in the Current Period, compared to a $62.5 million non-cash gain in the Prior Period. The risk management loss for the Current Period consisted of a $42.5 million non-cash loss related to changes in fair value of derivatives not designated as cash flow hedges, $35.7 million of reclassifications related to the settlement of such contracts, a $2.2 million non-cash loss associated with the ineffective portion of derivatives qualifying for cash flow hedge accounting, a $1.6 million non-cash gain associated with the portion of our interest rate swap that does not qualify for fair value hedge accounting, and a $1.1 million non-cash loss associated with the ineffective portion of our swaption. Risk management income for the Prior Period included a $61.5 million non-cash gain attributable to the change in fair value of certain derivatives not designated as cash flow hedges, and a non-cash gain of $1.0 million associated with the ineffective portion of our cash flow hedges.

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

Oil and Gas Marketing Sales. We generated $70.1 million in oil and gas marketing sales for third parties in the Current Period, with corresponding oil and gas marketing expenses of $67.7 million, for a net margin of $2.4 million. This compares to sales of $94.2 million, expenses of $91.4 million, and a net margin of $2.8 million in the Prior Period. The decrease in marketing sales and cost of sales was due primarily to a decrease in oil and gas prices in the Current Period compared to the Prior Period, partially offset by an increase in volumes marketed by Chesapeake Energy Marketing, Inc. in the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, increased to $46.3 million in the Current Period, a $9.7 million increase from the $36.6 million of production expenses incurred in the Prior Period. On a unit of production basis, production expenses were $0.54 and $0.46 per mcfe in the Current and Prior Periods, respectively. The increase in costs on a per unit basis in the Current Period is due primarily to increased field service costs, higher production costs associated with properties acquired in 2001 and an increase in ad valorem taxes. We expect that lease operating expenses per mcfe for the remainder of 2002 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $13.1 million and $24.3 million in the Current and Prior Periods, respectively. On a per unit basis, production taxes were $0.15 per mcfe in the Current Period compared to $0.31 per mcfe in the Prior Period. The decrease in the Current Period was the result of decreased prices and new statutory exemptions on certain wells in Oklahoma and Texas. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes for the remainder of 2002 to be approximately 6% - 7% of oil and gas sales revenues excluding any impact from hedging.

General and Administrative. General and administrative expenses, which are net of capitalized internal costs, were $8.2 million in the Current Period compared to $6.9 million in the Prior Period. The increase in the Current Period is a result of Chesapeake's continued growth.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $5.3 million and $3.9 million of internal costs in the Current Period and Prior Period, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for the remainder of 2002 will be between $0.10 and $0.11 per mcfe, which is approximately the same level as 2001 and the Current Period.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Period was $99.4 million, compared to $78.1 million in the Prior Period. The DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, increased from $0.98 in the Prior Period to $1.17 per mcfe in the Current Period. We expect the DD&A rate for the remainder of 2002 to be between $1.25 and $1.35 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $6.8 million in the Current Period, compared to $3.8 million in the Prior Period. The increase in the Current Period was primarily the result of higher depreciation recorded on recently acquired fixed assets. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from three to seven years. We expect depreciation and amortization of other assets to average between $0.08 and $0.10 per mcfe for the remainder of 2002 which approximates the current rate.

Interest and Other Income. Interest and other income for the Current Period was $4.7 million compared to $1.3 million in the Prior Period. The increase was primarily the result of additional interest income from significantly higher cash balances held during the Current Period as well as interest income recorded on our investment in senior secured notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $51.7 million in the Current Period from $48.9 million in the Prior Period. The increase in the Current Period was due to a $167 million increase in average long-term borrowings in the Current Period compared to the Prior Period, partially offset by income of $1.6 million earned on our interest rate swap during the Current Period. In addition to the interest expense reported, we capitalized $2.3 million of interest during each of the Current Period and 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 of our outstanding borrowings. We anticipate that capitalized interest for the remainder of 2002 will be between $2.0 million and $2.5 million.

Gothic Standby Credit Facility Costs. During the Prior Period, we obtained a standby commitment for a $275 million credit facility, consisting of a $175 million term loan and a $100 million revolving credit facility which, if needed, would have replaced our then existing revolving credit facility. The term loan was available to provide funds to repurchase any of Gothic Production Corporation's 11.125% senior secured notes tendered following the closing of the Gothic acquisition in January 2001 pursuant to a change-of-control offer to purchase. In February 2001, we purchased $1.0 million of notes tendered for 101% of such amount. We did not use the standby credit facility and the commitment terminated in February 2001. Chesapeake incurred $3.4 million of costs for the standby facility, which were recognized in the Prior Period.

Provision (Benefit) for Income Taxes. Chesapeake recorded an income tax benefit of $1.7 million in the Current Period, compared to income tax expense of $105.2 million in the Prior Period. Income tax expense for the Prior Period was comprised of $97.9 million related to our domestic operations and $7.3 million related to our Canadian operations which were sold on October 1, 2001. We anticipate that all 2002 income tax expense will be deferred.

Cash Flows From Operating, Investing, and Financing Activities

Cash Flows from Operating Activities. Cash provided by operating activities decreased 28% to $214.8 million during the Current Period compared to $297.0 million during the Prior Period. The decrease was due primarily to lower oil and gas prices realized during the Current Period.

Cash Flows from Investing Activities. Cash used in investing activities increased to $324.6 million during the Current Period from $302.0 million in the Prior Period. During the Current Period, we expended approximately $176.4 million to initiate drilling on 281 (123.7 net) wells and invested approximately $7.2 million in unproved properties. This compares to $179.9 million to initiate drilling on 280 (143.0 net) wells and $48.5 million to purchase unproved properties in the Prior Period. During the Current Period, we had acquisitions of oil and gas companies and properties of $124.3 million and no divestitures of oil and gas properties. This compares to acquisitions of oil and gas companies and properties of $53.1 million and divestitures of $0.2 million in the Prior Period. During the Current Period, we had additional investments in drilling rig equipment and other fixed assets of $18.6 million compared to $20.8 million in the Prior Period. The Current Period included additional investments in the common stock of two oil and gas companies totaling $2.4 million and $4.2 million in proceeds from the sale of RAM Energy, Inc. notes.

Cash Flows from Financing Activities. There was $1.6 million of cash used in financing activities in the Current Period, compared to cash provided by financing activities of $5.1 million in the Prior Period. The activity in the Current Period reflects the net increase in borrowings under our commercial bank credit facility of $45.0 million. This was primarily offset by the repurchase of $42.2 million of our 7.875% senior notes. We received $2.0 million in cash from the exercise of stock options, and $5.1 million was used to pay dividends on our 6.75% preferred stock. The activity in the Prior Period included increased borrowings under our credit facility of $135.0 million, $786.7 million received from the issuance of $800.0 million of 8.125% senior notes, $906.0 million used to redeem various senior notes, $12.2 million used to pay financing costs related to new debt issuance, and $2.8 million received from the exercise of stock options.

Liquidity and Capital Resources

Sources of Liquidity

Chesapeake had a working capital deficit of $19.6 million at June 30, 2002, including $6.3 million in cash. We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003 but under certain circumstances can be extended through June 2005. As of June 30, 2002, we had borrowed $45.0 million under the facility and were using $11.1 million of the facility to secure various letters of credit. As of August 2, 2002, borrowings under the credit facility had increased to $65.0 million, largely as a result of borrowings to fund an acquisition in late July 2002. The use of facility borrowings and long-term indebtedness to fund recent and pending acquisitions is discussed below under Investing and Financing Transactions. We believe we will have adequate resources, including operating cash flows, working capital and proceeds from our revolving bank credit facility, to fund our capital expenditure budget for exploration and development activities during the remainder of 2002, which is currently estimated to be $160 - $180 million. Further, our drilling program is largely discretionary and can be adjusted to match changing circumstances. Based on our current cash flow assumptions we expect operating cash flow to reach $380 - $400 million during 2002. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayments or other general corporate purposes in 2002.

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

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

Contractual Obligations and Commercial Commitments

We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of June 30, 2002, we had borrowed $45.0 million under this facility and were using $11.1 million of the facility to secure various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically.

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

As of June 30, 2002, senior notes represented $1.3 billion of our long-term debt and consisted of the following: $800.0 million principal amount of 8.125% senior notes due 2011, $250.0 million principal amount of 8.375% senior notes due 2008, $107.8 million principal amount of 7.875% senior notes due 2004 and $142.7 million principal amount of 8.5% senior notes due 2012. There are no scheduled principal payments required on any of the senior notes until March 2004, when $107.8 million is due, giving effect to the repurchase and retirement of $42.2 million of our 7.875% senior notes in the Current Period. Debt ratings for the senior notes are B1 by Moody's Investor Service, B+ by Standard & Poor's Ratings Services and BB- by Fitch Ratings. Debt ratings for our secured bank credit facility are Ba3 by Moody's Investor Service, BB by Standard & Poor's Ratings Services and BB+ by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly owned subsidiaries except Chesapeake Energy Marketing, Inc. guarantee the notes. We can acquire outstanding senior notes at either make-whole or redemption prices set forth in the respective indentures, and from time to time we acquire senior notes through market purchases. If we repurchase at least an additional $32.8 million of the 7.875% senior notes by August 31, 2003, we may extend the bank credit facility until June 2005 for an amount equal to the total revolving credit facility commitment less the outstanding amount of the 7.875% senior notes plus $50 million.

The indentures for the 8.125% and 8.375% 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 June 30, 2002, we estimate that secured commercial bank indebtedness of approximately $385 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., an unrestricted subsidiary.

Some of our commodity price and interest rate risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price and interest rate risk management transactions exceed certain levels. At June 30, 2002, we posted $10.0 million of collateral with one of our counterparties through a letter of credit issued under our bank credit facility. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and the level of volatility in natural gas and oil prices and interest rates.

Investing and Financing Transactions

On June 28, 2002, we acquired Canaan Energy Corporation in a cash merger through a Chesapeake subsidiary. Under the agreement, all outstanding common shares of Canaan, other than the Canaan shares already owned by Chesapeake, were purchased at $18.00 per share in cash, and the outstanding options to acquire Canaan common stock were converted into the right to receive, for each share of Canaan common stock to be received upon exercise, the merger consideration less the per share exercise price and withholding taxes. The aggregate net cash consideration for the merger was $120 million, including the retirement of Canaan's outstanding indebtedness of approximately $43 million.

In the Current Period, we purchased and subsequently retired $42.2 million of our 7.875% senior notes due 2004 for total consideration of $44.0 million, including accrued interest of $0.8 million and $1.0 million of redemption premium.

See Note 2 of the notes to consolidated financial statements included in this report for a discussion of our hedging activities and financial instruments.

In late July 2002, we completed an acquisition of oil and gas properties using bank facility borrowings to fund the cash purchase price of $38 million. We have entered into three definitive purchase agreements to acquire additional oil and gas properties for an aggregate cash purchase price of approximately $132 million. We expect to close these acquisitions during the third quarter of 2002. It is our intent to fund these acquisitions by issuing long-term unsecured notes through a private offering. If for any reason this market is not available, we intend to use the bank facility to fund the acquisitions.

Recently Issued Accounting Standards

See Note 8 of the notes to the consolidated financial statements included in this report for a summary of recently issued accounting standards.

Forward-Looking Statements

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

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

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

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

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

Oil and Gas Hedging Activities

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

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

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

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

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

	Volume	Average Strike Price	Weighted-Average Put Strike Price	Weighted-Average Call Strike Price	Weighted-Average Differential	SFAS 133 Hedge	Premiums Received	Fair Value at June 30, 2002 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
2002	4,280,000	$ 2.91	$ —	$ —	$ —	Yes	$ —	$ (1,486)
Cap-Swaps:								
2002	41,120,000	4.53	3.53	—	—	No	—	28,758
2003	51,100,000	3.60	2.60	—	—	No	—	(18,733)
Collars:								
2002	6,140,000	—	4.00	5.45	—	Yes	—	4,206
Straddles:								
2002	11,680,000	—	2.46	2.46	—	No	5,951	(9,506)
Strangles:								
2003	14,600,000	—	3.20	3.70	—	No	12,629	(13,357)
2004	14,640,000	—	3.40	3.90	—	No	15,884	(15,921)
Basis Protection Swaps:								
2003	91,250,000	—	—	—	(0.15)	No	—	(530)
2004	91,500,000	—	—	—	(0.15)	No	—	(1,278)
2005	98,550,000	—	—	—	(0.16)	No	—	(2,085)
2006	21,900,000	—	—	—	(0.17)	No	—	(437)
2007	31,025,000	—	—	—	(0.16)	No	—	(639)
2008	31,110,000	—	—	—	(0.16)	No	—	(654)
2009	21,900,000	—	—	—	(0.17)	No	—	(493)
Counter-Swaps:								
2003	45,700,000	3.74	—	—	—	No	—	6,239
Locked-Swaps:								
2002	—	—	—	—	—	No	—	8,117
2003	—	—	—	—	—	No	—	16,107
Total Gas							34,464	(1,692)
Oil (bbls):								
Swaps:								
2002	368,000	26.20	—	—	—	Yes	—	(19)
Cap-Swaps:								
2002	1,104,000	24.91	20.08	—	—	No	—	(1,779)
Locked-Swaps:								
2002	—	—	—	—	—	No	—	196
Total Oil							—	(1,602)
Total Gas and Oil							$ 34,464(a)	$ (3,294)(a)

(a) After adjusting for the $34.5 million premium paid to Chesapeake by the counterparty at the inception of the straddle and strangle contracts (which is recorded in cash provided by operating activities on the accompanying consolidated statements of cash flows), the net value of the combined hedging portfolio at June 30, 2002 was $31.2 million.

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

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

Fair value of contracts outstanding at January 1, 2002	$ 157,309
Change in fair value of contracts during period	(55,623)
Contracts realized or otherwise settled during the period	(61,989)
Fair value of new contracts when entered into during the period	(42,991)
Fair value of contracts outstanding at June 30, 2002	$ (3,294)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2002	2001	2002
Risk management income (loss):				
Change in fair value of derivatives not qualifying for hedge accounting	$ 61,495	$ 10,884	$ 61,495	$ (42,530)
Reclassification of gain on settled contracts	—	(10,630)	—	(35,707)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	960	(1,358)	960	(2,182)
Total	$ 62,455	$ (1,104)	$ 62,455	$ (80,419)

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

Based upon the market prices at June 30, 2002, we would expect to transfer approximately $11.3 million of the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of June 30, 2002 are expected to mature by December 31, 2004, with the exception of the basis protection swaps which extend to 2009.

Interest Rate Risk

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

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

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 coincide with the semi-annual interest payments on our 7.875% senior notes which are due on September 15 and March 15 of each year beginning September 15, 2002.

A portion of the interest rate swap was originally entered into to convert $129.0 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of the interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge under which the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease in carrying value of the debt. See Note 5 of the notes to consolidated financial statements included in this report for the adjustments made to the carrying value of debt at June 30, 2002. During the Current Quarter, $21.2 million of the 7.875% senior notes were purchased and subsequently retired resulting in a $0.4 million gain on the repurchase of debt related to the interest rate swap. As a result of these repurchases, $107.8 million of the interest rate swap was designated as a fair value hedge under SFAS 133 at June 30, 2002.

Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the swap agreement.

The remaining $92.2 million of the interest rate swap has not been designated as a fair value hedge. The mark-to-market value of this portion of the instrument is recorded as a derivative asset or liability on the consolidated balance sheets with the offsetting amount reflected in risk management income (loss) on the consolidated statements of operations. The amount recorded in risk management income (loss) will be reversed and reflected in interest expense over the term of the swap.

The estimated fair value of the interest rate swap at June 30, 2002 was an asset of approximately $5.0 million comprised of $1.6 million reflected as risk management income, $1.4 million reflected as an increase in the carrying value of our long-term debt, $1.6 million reflected as a reduction in interest expense, and $0.4 million reflected as other income related to the gain on the repurchase of debt.

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

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

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 are made on July 2 and January 2 of each year beginning January 2, 2003. The estimated fair value of the interest rate swap at June 30, 2002 was negligible.

In July 2002, we closed both interest rate swaps for a combined gain of $8.6 million. Gains totaling $6.6 million, in addition to the $2.0 million gain already realized in the Current Quarter, will be recognized as reductions to interest expense over the remaining terms of the swaps.

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

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

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

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

We have recorded a decrease in the carrying value of the debt of $7.8 million related to the swaption as of June 30, 2002. Of this amount, $8.9 million represents the mark-to-market valuation of the swaption offset by $1.1 million estimated ineffectiveness of the swaption as determined under SFAS 133. See Note 5 of the notes to consolidated financial statements included in this report for the adjustments made to the carrying value of the debt at

June 30, 2002. Results of the swaption will be reflected as adjustments to interest expense in the corresponding months covered by the swaption agreement.

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

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002
Risk management income:		
Change in fair value of derivatives not qualifying for fair value hedge accounting	$ 2,454	$ 2,301
Reclassification of gains on settled contracts	(731)	(731)
Ineffective portion of derivatives qualifying for fair value hedge accounting	(1,100)	(1,100)
Total	$ 623	$ 470

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.

	June 30, 2002								
	Years of Maturity								
	2002	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
	($ in millions)								
Liabilities:									
Long-term debt, including current portion — fixed rate	$ 0.1	$ —	$ 107.8	$ —	$ —	$ —	$1,192.6	$1,300.5(a)	$1,297.3
Average interest rate	9.1%	—	7.9%	—	—	—	8.2%	8.2%	8.2%
Long-term debt — variable rate	$ —	$ 45.0	$ —	$ —	$ —	$ —	$ —	$ 45.0	$ 45.0
Average interest rate	—	5.25%	—	—	—	—	—	5.25%	5.25%

(a) This amount does not include the discount included in long-term debt of ($12.7) million, the value of the interest rate swaps of $1.4 million and the value of the swaption of ($7.8) million.

Marketing Activities

In addition to marketing our own oil and gas production, our marketing activities include marketing oil and gas production for working interest owners and royalty owners in the wells that we operate. Such activities include the operation of gathering systems and the sale of oil and natural gas under various arrangements. Recently royalty owners have commenced litigation against a number of companies in the oil and gas production business claiming that amounts paid for production attributable to the royalty owners' interest violated the terms of the applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the applicable leases and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. A portion of the foregoing litigation has been commenced as class action suits including four class action suits filed against Chesapeake and others which we believe do not represent valid claims or, if valid, are not material. As new cases are decided and the law in this area continues to develop, our liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor the court decisions to ensure that our operations and practices minimize any exposure and to recognize any charges that may be appropriate.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

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

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

Not applicable

Item 3. *Defaults Upon Senior Securities*

Not applicable

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

Three matters were submitted to a vote of the shareholders at Chesapeake's annual meeting of shareholders held on June 7, 2002: the election of directors, the adoption of a stock option plan for employees and consultants and the adoption of a stock option plan for non-employee directors. In the election of directors, Aubrey K. McClendon received 153,808,677 votes for election and 4,670,442 shares were withheld from voting for Mr. McClendon; and Shannon T. Self received 153,868,588 votes for election and 4,610,531 share were withheld from voting for Mr. Self. The other directors whose terms continued after the meeting are Edgar F. Heizer, Jr., Breene M. Kerr, Tom L. Ward and Frederick B. Whittemore. In the adoption of our 2002 Stock Option Plan, 121,950,327 votes were received for the adoption of the plan, 36,092,764 votes were received against adoption of the plan and 436,025 shares were withheld from voting on this proposal. In the adoption of our 2002 Non-Employee Director Stock Option Plan, 120,983,754 votes were received for the adoption of the plan, 36,993,462 votes were received against adoption of the plan and 501,899 shares were withheld from voting on this proposal. There were no broker non-votes.

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
3.1	Chesapeake's Restated Certificate of Incorporation together with the Certificate of Designation for the 6.75% Cumulative Convertible Preferred Stock of Chesapeake and the Certificate of Designation for the Series A Junior Participating Preferred Stock of Chesapeake. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's registration statement on Form S-3 (No. 333-96863) filed July 22, 2002.
4.6.1	Second Amendment dated June 4, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.

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

(b) *Reports on Form 8-K*

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

On April 4, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing first quarter 2002 earnings release and conference call dates.

On April 16, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing that our Board of Directors had declared a regular quarterly dividend on our preferred stock.

On April 23, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing an agreement to acquire Canaan Energy Corporation.

On April 30, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing first quarter 2002 financial and operating results. We furnished under Item 9 updates to our operational and financial guidance for 2002 included in the press release.

On June 5, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing that our 2002 Annual Meeting of Shareholders would be webcast live.

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: August 5, 2002

INDEX TO EXHIBITS

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