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, 2008

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]

As of August 6, 2008, there were 579,164,169 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
INDEX TO FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2008

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ 1
Accounts receivable	1,603	1,074
Short-term derivative instruments	—	203
Deferred income taxes	1,348	1
Inventory	159	87
Other	65	30
Total Current Assets	3,175	1,396
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	30,629	27,656
Unevaluated properties	7,751	5,641
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(8,142)	(7,112)
Total natural gas and oil properties, at cost based on full-cost accounting	30,238	26,185
Other property and equipment:		
Natural gas gathering systems and treating plants	1,646	1,135
Buildings and land	1,258	816
Drilling rigs and equipment	177	106
Natural gas compressors	121	63
Other	391	327
Less: accumulated depreciation and amortization of other property and equipment	(368)	(295)
Total Other Property and Equipment	3,225	2,152
Total Property and Equipment	33,463	28,337
OTHER ASSETS:		
Investments	644	612
Long-term derivative instruments	—	4
Other assets	741	385
Total Other Assets	1,385	1,001
TOTAL ASSETS	$ 38,023	$ 30,734

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS – (Continued)
(Unaudited)

	June 30, 2008	December 31, 2007
	($ in millions)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,389	$ 1,262
Accrued liabilities	785	717
Current maturities of long-term debt	690	—
Short-term derivative instruments	3,518	174
Revenues and royalties due others	719	433
Accrued interest	196	175
Total Current Liabilities	7,297	2,761
LONG-TERM LIABILITIES:		
Long-term debt, net	13,014	10,950
Deferred income tax liability	3,505	3,966
Asset retirement obligation	255	236
Long-term derivative instruments	3,110	408
Revenues and royalties due others	48	42
Other liabilities	518	241
Total Long-Term Liabilities	20,450	15,843
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of June 30, 2008 and December 31, 2007, entitled in liquidation to $345 million	345	345
5.00% cumulative convertible preferred stock (series 2005B), 3,031,500 and 5,750,000 shares issued and outstanding as of June 30, 2008 and December 31, 2007, respectively, entitled in liquidation to $303 million and $575 million, respectively	303	575
6.25% mandatory convertible preferred stock, 143,768 shares issued and outstanding as of June 30, 2008 and December 31, 2007, entitled in liquidation to $36 million	36	36
4.125% cumulative convertible preferred stock, 3,059 and 3,062 shares issued and outstanding as of June 30, 2008 and December 31, 2007, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of June 30, 2008 and December 31, 2007, entitled in liquidation to $1 million	1	1
Common Stock, $.01 par value, 750,000,000 shares authorized, 545,778,065 and 511,648,217 shares issued at June 30, 2008 and December 31, 2007, respectively	5	5
Paid-in capital	8,425	7,032
Retained earnings	2,338	4,150
Accumulated other comprehensive income (loss), net of tax of $722 million and $6 million, respectively	(1,174)	(11)
Less: treasury stock, at cost; 499,723 and 500,821 common shares as of June 30, 2008 and December 31, 2007, respectively	(6)	(6)
Total Stockholders' Equity	10,276	12,130
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 38,023	$ 30,734

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
	($ in millions except per share data)			
REVENUES:				
Natural gas and oil sales	$ (1,594)	$ 1,548	$ (821)	$ 2,672
Natural gas and oil marketing sales	1,099	523	1,895	945
Service operations revenue	40	34	82	67
Total Revenues	(455)	2,105	1,156	3,684
OPERATING COSTS:				
Production expenses	219	153	419	295
Production taxes	88	53	163	95
General and administrative expenses	101	54	180	107
Natural gas and oil marketing expenses	1,075	504	1,849	911
Service operations expense	32	23	67	44
Natural gas and oil depreciation, depletion and amortization	523	442	1,038	835
Depreciation and amortization of other assets	40	40	77	76
Total Operating Costs	2,078	1,269	3,793	2,363
INCOME (LOSS) FROM OPERATIONS	(2,533)	836	(2,637)	1,321
OTHER INCOME (EXPENSE):				
Interest and other income (expense)	(1)	1	(11)	10
Interest expense	(63)	(84)	(163)	(162)
Gain on sale of investments	—	83	—	83
Total Other Income (Expense)	(64)	—	(174)	(69)
INCOME (LOSS) BEFORE INCOME TAXES	(2,597)	836	(2,811)	1,252
INCOME TAX EXPENSE (BENEFIT):				
Current	3	11	3	11
Deferred	(1,003)	307	(1,085)	465
Total Income Tax Expense (Benefit)	(1,000)	318	(1,082)	476
NET INCOME (LOSS)	(1,597)	518	(1,729)	776
PREFERRED STOCK DIVIDENDS	(9)	(26)	(20)	(52)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(43)	—	(43)	—
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (1,649)	$ 492	$ (1,792)	$ 724
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (3.17)	$ 1.09	$ (3.54)	$ 1.60
Assuming dilution	$ (3.17)	$ 1.01	$ (3.54)	$ 1.51
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.0675	$ 0.1425	$ 0.1275
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	521	452	507	452
Assuming dilution	521	515	507	515

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (1,729)	$ 776
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,120	915
Deferred income taxes	(1,087)	460
Unrealized losses on derivatives	4,538	152
Realized (gains) losses on financing derivatives	32	(51)
Stock-based compensation	61	30
Gain on sale of investment	—	(83)
Other	20	1
Change in assets and liabilities	(201)	(78)
Cash provided by operating activities	2,754	2,122
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(2,935)	(2,598)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(3,015)	(1,123)
Proceeds from sale of volumetric production payment	616	—
Divestitures of proved and unproved properties and leasehold	247	—
Additions to other property and equipment	(1,229)	(484)
Additions to investments	(81)	(12)
Proceeds from sale of drilling rigs and equipment	34	87
Proceeds from sale of compressors	51	—
Proceeds from sale of investments	—	124
Deposits for acquisitions	(19)	(5)
Sale of other assets	2	8
Cash used in investing activities	(6,329)	(4,003)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	6,758	3,544
Payments on long-term borrowings	(6,195)	(2,624)
Proceeds from issuance of senior notes, net of offering costs	2,136	1,124
Proceeds from issuance of common stock, net of offering costs	1,011	—
Cash paid for common stock dividends	(66)	(54)
Cash paid for preferred stock dividends	(22)	(52)
Derivative settlements	(93)	(52)
Net increase (decrease) in outstanding payments in excess of cash balance	47	(10)
Cash received from exercise of stock options	7	6
Excess tax benefit from stock-based compensation	21	8
Other financing costs	(30)	(8)
Cash provided by financing activities	3,574	1,882
Net increase (decrease) in cash and cash equivalents	(1)	1
Cash and cash equivalents, beginning of period	1	3
Cash and cash equivalents, end of period	$ —	$ 4

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – (Continued)
(Unaudited)

	Six Months Ended June 30,	
	2008	2007
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 140	$ 123
Income taxes, net of refunds received	$ 5	$ 15

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of June 30, 2008 and 2007, accrued dividends payable on our common and preferred stock were $48 million and $56 million, respectively.

For the six months ended June 30, 2008 and 2007, natural gas and oil properties were adjusted by $12 million and $101 million, respectively, for income tax liabilities related to acquisitions.

For the six months ended June 30, 2008 and 2007, natural gas and oil properties were adjusted by ($6) million and $55 million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

We recorded non-cash asset additions to net natural gas and oil properties of $6 million and $8 million for the six months ended June 30, 2008 and 2007, respectively, for asset retirement obligations.

For the six months ended June 30, 2008, holders of our 5.0% (Series 2005B) cumulative convertible preferred stock exchanged 2,718,500 shares for 7,780,703 shares of common stock in privately negotiated exchanges.

For the six months ended June 30, 2008, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock, and for the six months ended June 30, 2007, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 960	$ 1,958
Exchange of common stock for 2,718,500 shares of 5.00% preferred stock (series 2005B)	(272)	—
Balance, end of period	688	1,958
COMMON STOCK:		
Balance, beginning of period	5	5
Issuance of 23,000,000 shares of common stock	—	—
Exchange of 7,780,883 and 180 shares of common stock for preferred stock	—	—
Balance, end of period	5	5
PAID-IN CAPITAL:		
Balance, beginning of period	7,032	5,873
Issuance of 23,000,000 shares of common stock	1,052	—
Stock-based compensation	82	42
Exercise of stock options	7	6
Offering expenses	(41)	—
Exchange of 7,780,883 and 180 shares of common stock for preferred stock	272	—
Tax benefit from exercise of stock options and restricted stock	21	8
Balance, end of period	8,425	5,929
RETAINED EARNINGS:		
Balance, beginning of period	4,150	2,913
Net income (loss)	(1,729)	776
Dividends on common stock	(73)	(58)
Dividends on preferred stock	(10)	(51)
Adoption of FIN 48	—	(4)
Balance, end of period	2,338	3,576
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(11)	528
Hedging activity	(1,191)	(356)
Marketable securities activity	28	(2)
Balance, end of period	(1,174)	170
TREASURY STOCK – COMMON:		
Balance, beginning of period	(6)	(26)
Release of 1,098 and 463,085 shares for company benefit plans	—	14
Balance, end of period	(6)	(12)
TOTAL STOCKHOLDERS' EQUITY	$ 10,276	$ 11,626

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	($ in millions)			
Net income (loss)	$ (1,597)	$ 518	$ (1,729)	$ 776
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of ($530) million, $67 million, ($833) million and ($65) million	(865)	109	(1,357)	(104)
Reclassification of (gain) loss on settled contracts, net of income taxes of $103 million, ($40) million, $52 million and ($178) million	167	(64)	85	(292)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $24 million, $4 million, $49 million and $24 million	39	6	80	40
Unrealized (gain) loss on marketable securities, net of income taxes of $16 million, ($2) million, $17 million and ($1) million	27	(4)	28	(2)
Comprehensive income (loss)	$ (2,229)	$ 565	$ (2,893)	$ 418

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission. Chesapeake's annual report on Form 10-K for the year ended December 31, 2007 ("2007 Form 10-K") includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three and six months ended June 30, 2008 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, 2008 (the "Current Quarter" and the "Current Period", respectively) and the three and six months ended June 30, 2007 (the "Prior Quarter" and the "Prior Period", respectively).

Income Taxes

Chesapeake adopted the provisions of FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* on January 1, 2007. As of June 30, 2008, the amount of unrecognized tax benefits related to AMT liabilities associated with uncertain tax positions was $134 million. These AMT liabilities can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have an effect on the effective tax rate. At June 30, 2008, we had a liability of $9 million for interest related to these same uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties, income taxes and business combinations to be critical policies. These policies are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2007 Form 10-K.

2. Financial Instruments and Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of June 30, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price 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.
- Basis protection swaps are arrangements that guarantee a price differential for natural gas or oil from a specified delivery point. For Mid-Continent basis protection swaps, which typically have negative differentials to NYMEX, 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. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

- For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.
- For call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.
- 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, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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

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

Gains or losses from certain derivative transactions are reflected as adjustments to natural gas and oil sales on the condensed consolidated statements of operations. Realized gains (losses) are included in natural gas and oil sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). The components of natural gas and oil sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
	($ in millions)			
Natural gas and oil sales	$ 2,233	$ 1,199	$ 3,925	$ 2,200
Realized gains (losses) on natural gas and oil derivatives	(423)	197	(208)	630
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(3,340)	162	(4,409)	(94)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(64)	(10)	(129)	(64)
Total natural gas and oil sales	$ (1,594)	$ 1,548	$ (821)	$ 2,672

The estimated fair values of our natural gas and oil derivative instruments as of June 30, 2008 and December 31, 2007 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2008	December 31, 2007
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (1,772)	$ (54)
Natural gas basis protection swaps	184	151
Fixed-price natural gas knockout swaps[(a)]	(1,667)	108
Natural gas call options[(b)]	(1,426)	(230)
Fixed-price natural gas collars[(c)]	(470)	4
Fixed-price oil swaps	(153)	(110)
Fixed-price oil knockout swaps	(837)	(125)
Fixed-price oil cap-swaps	(34)	(17)
Oil call options[(d)]	(360)	(96)
Fixed-price oil collars	(16)	—
Estimated fair value	$ (6,551)	$ (369)

(a) After adjusting for $39 million and $0 of unrealized premiums, the cumulative unrealized gain (loss) related to these knockout swaps as of June 30, 2008 and December 31, 2007 was ($1.628) billion and $108 million, respectively.

(b) After adjusting for $509 million and $255 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of June 30, 2008 and December 31, 2007 was ($917) million and $25 million, respectively.

(c) After adjusting for $122 million and ($8) million of unrealized premium (discount), the cumulative unrealized gain (loss) related to these collars as of June 30, 2008 and December 31, 2007 was ($348) million and ($4) million, respectively.

(d) After adjusting for $27 million and $29 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of June 30, 2008 and December 31, 2007 was ($333) million and ($67) million, respectively.

Extreme volatility in natural gas and oil prices in 2008 has created wide swings in the mark-to-market value of our natural gas and oil derivatives. As of June 30, 2008, we had a net natural gas and oil derivative liability of $6.551 billion as a result of significant increases in natural gas and oil prices since December 31, 2007. Subsequent to June 30, 2008, natural gas and oil prices have decreased significantly causing our natural gas and oil hedges to move in our favor. Should prices on September 30, 2008 be the same as current prices, we believe substantially all of the 2008 unrealized loss on natural gas and oil derivatives would be reversed and reported as an unrealized gain in the 2008 third quarter.

Based upon the market prices at June 30, 2008, we expect to transfer approximately $759 million (net of income taxes) of the loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of June 30, 2008 are expected to mature by December 31, 2022.

We have six secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet any additional collateral coverage requirements. The hedging facilities are subject to a per annum exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time. The fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities (a)					
	#1	#2	#3	#4	#5	#6
			($ in millions)			
Fair value of outstanding transactions, as of June 30, 2008	$ (214)	$(1,832)	$ (1,181)	$ (181)	$ (273)	$ (760)
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2020	2012	2012	2012

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 – 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 – 6.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were $4 million, a nominal amount, $4 million and ($2) million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Unrealized gains (losses) included in interest expense were $14 million, $7 million, $1 million and $6 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

As of June 30, 2008, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:							
January 2008 – November 2020	$2,750	6.87%	6 month LIBOR plus 261 basis points	—	Yes	$ —	$ (87)
January 2008 – January 2018	$ 500	6.94%	6 month LIBOR plus 290 basis points	—	No	2	(13)
Floating to Fixed Swaps:							
August 2007 – August 2010	$ 825	4.74%	3 month LIBOR	—	No	—	(16)
Swaption:							
April 2008 – October 2008	$ 250	6.50%	—	—	No	4	(9)
Call Options:							
January 2008 – July 2010	$ 500	6.56%	—	—	No	4	(8)
Collars:							
August 2007 – August 2010	$ 800	—	—	5.37%-4.52%	No	—	(17)
						$ 10	$ (150)

In the Current Period, we sold call options on three of our interest rate swaps and received $7 million in premiums. Three call options were exercised in the Current Period resulting in the termination of three interest rate swaps and one call option expired unexercised. Additionally, we sold two swaptions in the Current Period and received $6 million in premiums. One swaption was exercised during the Current Period and resulted in a new interest rate swap.

In the Current Period, we closed 21 interest rate swaps for gains totaling $56 million. These interest rate swaps were designated as fair value hedges and the settlement amounts received will be amortized as a reduction to interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake €19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($945 million at June 30, 2008) using an exchange rate of $1.5748 to €1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $73 million at June 30, 2008.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil price and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Recently there have been concerns about the ability of certain investment banks to continue to meet their financial obligations. We monitor our counterparties and do not believe a failure by an investment bank counterparty would have a material negative impact on our liquidity.

Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Additionally, we are exposed to credit risk associated with the indemnification related to the litigation discussed below in Note 3.

3. Contingencies and Commitments

Litigation

We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake's wholly-owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit filed in 2003 in the Circuit Court of Roane County, West Virginia by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR's operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. The jury found fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. On June 28, 2007, the Circuit Court sustained the jury verdict for punitive damages, and on September 27, 2007, it denied all post-trial motions. The defendants stayed the judgment during the pendency of their appeal to the West Virginia Supreme Court of Appeals by filing an irrevocable letter of credit in the amount of $50 million. They filed their initial Petition for Appeal on January 24, 2008. On May 22, 2008, the West Virginia Supreme Court of Appeals refused to hear the appeal. NiSource and Chesapeake intend to file a petition for writ of certiorari to the United States Supreme Court in August 2008, asserting among other things that their constitutional rights were violated by the manner in which punitive damages were awarded, the amount of punitive damages, and the lack of meaningful state court appellate review of the punitive damages award. The U.S. Supreme Court may or may not decide to accept the appeal. The West Virginia Supreme Court of Appeals has granted a stay of the judgment until September 23, 2008, pending further appeal.

Chesapeake has established an accrual for amounts it believes will not be indemnified. We have also recorded a non-current payable in the amount of the additional damages awarded the plaintiffs and an equal offsetting receivable for the expected NiSource indemnification if a final nonappealable judgment for the verdict amount should be entered. Chesapeake believes this litigation will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

Employment Agreements with Officers

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing January 1, 2008. The term of the agreement is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer's base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation upon the happening of certain events following a change of control. The agreement further provides that any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, incapacity, death, or retirement at or after age 55, and any unexercised stock options will not terminate as the result of termination of employment. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer’s base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death, or retirement at or after age 55.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at June 30, 2008.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 80 drilling rigs and related equipment for $647 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for rental payments of approximately $90 million annually. The lease obligations are guaranteed by Chesapeake and its other material subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to service operations expense over the lease term. Under the rig leases, we have the option to purchase the rigs in 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal. As of June 30, 2008, Chesapeake's drilling subsidiaries had contracted to acquire 26 rigs to be constructed during 2008. The total remaining cost of the rigs is estimated to be approximately $335 million. Our intent is to sell and lease back those rigs as they are delivered. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2008, the minimum aggregate future rig lease payments were approximately $628 million.

Compressor Leases

In 2007 and 2008, our midstream subsidiaries sold a significant portion of their existing compressor fleet, consisting of 1,300 compressors, for $240 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate rental payments of approximately $28 million annually. The lease obligations are guaranteed by Chesapeake and its other material subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to natural gas and oil marketing expenses over the lease term. Under the leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. Through 2009, approximately 450 new compressors are on order for approximately $217 million and our intent is to sell and lease back those compressors as they are delivered. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2008, the minimum aggregate future compressor lease payments were approximately $250 million.

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from one to 93 years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter's Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. As of June 30, 2008, the aggregate amount of such required demand payments was approximately $713 million (excluding demand charges for pipeline projects that are currently seeking regulatory approval).

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 32 rigs with terms of one to three years. As of June 30, 2008, the aggregate drilling rig commitment was approximately $218 million.

Gas Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short term in nature. We have also committed to purchase natural gas associated with volumetric production payment transactions. The purchase commitments extend over 11 to 15 year terms based on market prices at the time of production, and the purchased natural gas will be resold. As of June 30, 2008, we were obligated to purchase 290 bcfe under the terms of the volumetric production payments.

Other Commitments

We own a 49% interest in Mountain Drilling, a company that specializes in hydraulic drilling rigs which are ideal for drilling in urban areas. Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company up to $32 million each through December 31, 2009. At June 30, 2008, Mountain Drilling owed Chesapeake $19 million under this agreement.

We invested in Ventura Refining and Transmission LLC in early 2007 and today own a 25% interest. There were no refineries in western Oklahoma until Ventura opened its refinery in 2006. We have an agreement to lend Ventura Refining and Transmission LLC up to $31 million through January 31, 2017. At June 30, 2008, there was $28 million outstanding under this agreement. Additionally, we have agreed to guarantee up to $70 million in commitments for Ventura to support its operating activities. As of June 30, 2008, we had guaranteed $61 million.

4. Net Income (Loss) Per Share

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

For the Current Quarter and the Current Period, there was no difference between actual weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares, which are used in computing EPS assuming dilution as a result of the net losses to common shareholders.

The Current Quarter diluted shares do not include the effect of (i) outstanding stock options to purchase 2.3 million shares of common stock at a weighted average exercise price of $7.96, (ii) 7.6 million shares of unvested restricted stock at a weighted average grant-date fair value of $34.22, (iii) 2.7 million shares related to our 2.75% Contingent Convertible Senior Notes due 2035, (iv) 3.0 million common stock equivalent of preferred stock outstanding prior to conversion of our 5.00% convertible preferred stock (Series 2005B) and (v) the assumed conversion of the following outstanding preferred stock:

- 4.125% preferred stock convertible into 184,019 common shares,
- 5.00% (Series 2005) convertible preferred stock convertible into 19,443 common shares,
- 5.00% (Series 2005B) convertible preferred stock convertible into 7,760,336 common shares,
- 4.50% preferred stock convertible into 7,810,800 common shares, and
- 6.25% mandatory convertible preferred stock convertible into 1,031,175 common shares.

The Current Period diluted shares do not include the effect of (i) outstanding stock options to purchase 2.5 million shares of common stock at a weighted average exercise price of $7.96, (ii) 6.9 million shares of unvested restricted stock at a weighted average grant-date fair value of $34.22, (iii) 2.7 million shares related to our 2.75% Contingent Convertible Senior Notes due 2035, (iv) 5.0 million common stock equivalent of preferred stock outstanding prior to conversion of our 5.00% convertible preferred stock (Series 2005B) and (v) the assumed conversion of the following outstanding preferred stock:

- 4.125% preferred stock convertible into 184,019 common shares,
- 5.00% (Series 2005) convertible preferred stock convertible into 19,443 common shares,
- 5.00% (Series 2005B) convertible preferred stock convertible into 7,760,336 common shares,

- 4.50% preferred stock convertible into 7,810,800 common shares, and
- 6.25% mandatory convertible preferred stock convertible into 1,031,175 common shares.

Reconciliations for the three and six months ended June 30, 2007 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Three Months Ended June 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 492	452	$ 1.09
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.50% convertible preferred stock	—	8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)	—	18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)	—	15	
Common shares assumed issued for 6.25% convertible preferred stock	—	16	
Employee stock options	—	4	
Restricted stock	—	2	
Preferred stock dividends	26	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 518	515	$ 1.01
For the Six Months Ended June 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 724	452	$ 1.60
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:	—		
Common shares assumed issued for 4.50% convertible preferred stock	—	8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)	—	18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)	—	15	
Common shares assumed issued for 6.25% convertible preferred stock	—	16	
Employee stock options	—	4	
Restricted stock	—	2	
Preferred stock dividends	52	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 776	515	$ 1.51

5. Stockholders' Equity, Restricted Stock and Stock Options

The following is a summary of the changes in our common shares outstanding for the six months ended June 30, 2008 and 2007:

	2008	2007
	(in thousands)	
Shares outstanding at January 1	511,648	458,601
Common stock issuance	23,000	—
Preferred stock conversions	7,781	—
Stock option exercises	1,213	985
Restricted stock issuances net of terminations	2,136	12,206
Shares outstanding at June 30	545,778	471,792

In the Prior Period, we issued 9.8 million shares of restricted stock to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in August 2009 with the remaining 50% vesting in August 2011.

The following is a summary of the changes in our preferred shares outstanding for the six months ended June 30, 2008 and 2007:

	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)		
Shares outstanding at January 1, 2008	3	5	3,450	5,750	144
Conversion/exchange of preferred for common stock	—	—	—	(2,718)	—
Shares outstanding at June 30, 2008	3	5	3,450	3,032	144
Shares outstanding at January 1, 2007 and June 30, 2007	3	4,600	3,450	5,750	2,300

In connection with the exchanges and conversions noted above, we recorded a loss of $43 million in both the Current Quarter and the Current Period. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the common stock issuable pursuant to the original conversion terms of the preferred stock.

During the Current Period, 2,718,500 shares of our 5.0% (series 2005B) cumulative convertible preferred stock were exchanged for 7,780,703 shares of common stock in privately negotiated exchange transactions.

During the Current Period, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock.

During the Prior Period, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock.

Stock-Based Compensation

Chesapeake's stock-based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized are recognized as general and administrative expenses, production expenses, natural gas and oil marketing expenses or service operations expense. We recorded the following stock-based compensation during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
		($ in millions)		
Natural gas and oil properties	$ 26	$ 12	$ 51	$ 22
General and administrative expenses	21	12	40	22
Production expenses	7	3	14	6
Natural gas and oil marketing expenses	2	1	4	1
Service operations expense	1	—	3	1
Total	$ 57	$ 28	$ 112	$ 52

Restricted Stock. Chesapeake regularly issues shares of restricted common stock to employees and to non-employee directors. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four or five years from the date of grant for employees and three years for non-employee directors.

A summary of the changes in unvested shares of restricted stock during the Current Period is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2008	19,688,759	$ 32.42
Granted	3,170,300	$ 40.74
Vested	(1,950,383)	$ 26.48
Forfeited	(412,347)	$ 34.88
Unvested shares as of June 30, 2008	20,496,329	$ 34.22

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $86 million based on the stock price at the time of vesting.

As of June 30, 2008, there was $576 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.84 years.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to restricted stock of $3 million, a nominal amount, $9 million and $1 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

Stock Options. Prior to 2006, we granted stock options under several stock compensation plans. Outstanding options expire ten years from the date of grant and vest over a four-year period.

The following table provides information related to stock option activity during the Current Period:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in millions)
Outstanding at January 1, 2008	4,445,455	$ 7.55	4.37	$ 141
Exercised	(1,219,160)	$ 6.46		$ 53
Forfeited	(1,000)	$ 15.48		
Expired	(133)	$ 9.57		
Outstanding at June 30, 2008	3,225,162	$ 7.96	4.06	$ 187
Exercisable at June 30, 2008	3,219,162	$ 7.94	4.05	$ 187

(a) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock exceeds the exercise price of the option.

As of June 30, 2008, unrecognized compensation cost related to unvested stock options was nominal.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $7 million, $4 million, $12 million and $7 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

6. Senior Notes and Revolving Bank Credit Facility

Our total debt consisted of the following as of June 30, 2008 and December 31, 2007:

	June 30, 2008	December 31, 2007
	($ in millions)	
7.5% Senior Notes due 2013	$ 364	$ 364
7.625% Senior Notes due 2013	500	500
7.0% Senior Notes due 2014	300	300
7.5% Senior Notes due 2014	300	300
6.375% Senior Notes due 2015	600	600
7.75% Senior Notes due 2015[(a)]	300	300
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.25% Euro-denominated Senior Notes due 2017[(b)]	945	876
6.5% Senior Notes due 2017	1,100	1,100
6.25% Senior Notes due 2018	600	600
7.25% Senior Notes Due 2018	800	—
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035[(c)]	690	690
2.5% Contingent Convertible Senior Notes due 2037[(c)]	1,650	1,650
2.25% Contingent Convertible Senior Notes due 2038[(c)]	1,380	—
Revolving bank credit facility	2,513	1,950
Discount on senior notes	(100)	(105)
Impact of interest rate derivatives[(d)]	(8)	55
Total notes payable and long-term debt	$ 13,704	$ 10,950
Less current maturities of long-term debt[(c)]	(690)	—
Total notes payable and long-term debt, net of current maturities	$ 13,014	$ 10,950

(a) The 7.75% Senior Notes due 2015 were redeemed on July 7, 2008.

(b) The principal amount shown is based on the dollar/euro exchange rate of $1.5748 to €1.00 and $1.4603 to €1.00 as of June 30, 2008 and December 31, 2007, respectively. See Note 2 for information on our related cross currency swap.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is that the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the second quarter of 2008, the price of our common stock exceeded the threshold level for the 2.75% Contingent Convertible Senior Notes due 2035 during the specified period and, as a result, the holders of our 2.75% Contingent Convertible Senior Notes have the option to convert their notes into cash and common stock in the third quarter of 2008. While our 2.75% Contingent Convertible Senior Notes are classified as current debt in our balance sheet as of June 30, 2008, based on current trading prices for the notes, holders currently would realize greater value by selling their notes in the open market as opposed to converting them into cash and common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$48.83	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$64.477	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$107.36	June 14, 2019

(d) See Note 2 for discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit 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; incur liens; enter into sale/leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our subsidiaries' ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

We have a $3.5 billion syndicated revolving bank credit facility which matures in November 2012. As of June 30, 2008, we had $2.513 billion in outstanding borrowings under our facility and utilized approximately $6 million of the facility for various letters of credit. Borrowings under our facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 0.75% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.57 to 1 and our indebtedness to EBITDA ratio was 2.05 to 1 at June 30, 2008. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

Two of our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility. The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned subsidiaries except minor subsidiaries.

7. Segment Information

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production operational segment and natural gas and oil marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and oil. The marketing segment is responsible for gathering, processing, compressing, transporting and selling natural gas and oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations which are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the marketing segment's sale of natural gas and oil related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled $1.787 billion, $893 million, $3.076 billion and $1.598 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. The following table presents selected financial information for Chesapeake's operating segments. Our drilling rig and trucking service operations are presented in "Other Operations".

	Exploration and Production	Marketing	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)		
For the Three Months Ended June 30, 2008:					
Revenues	$ (1,594)	$ 2,886	$ 154	$ (1,901)	$ (455)
Intersegment revenues	—	(1,787)	(114)	1,901	—
Total revenues	$ (1,594)	$ 1,099	$ 40	$ —	$ (455)
Income (loss) before income taxes	$ (2,614)	$ 15	$ 27	$ (25)	$ (2,597)
For the Three Months Ended June 30, 2007:					
Revenues	$ 1,548	$ 1,416	$ 116	$ (975)	$ 2,105
Intersegment revenues	—	(893)	(82)	975	—
Total revenues	$ 1,548	$ 523	$ 34	$ —	$ 2,105
Income before income taxes	$ 822	$ 10	$ 36	$ (32)	$ 836
For the Six Months Ended June 30, 2008:					
Revenues	$ (821)	$ 4,971	$ 303	$ (3,297)	$ 1,156
Intersegment revenues	—	(3,076)	(221)	3,297	—
Total revenues	$ (821)	$ 1,895	$ 82	$ —	$ 1,156
Income (loss) before income taxes	$ (2,842)	$ 30	$ 47	$ (46)	$ (2,811)
For the Six Months Ended June 30, 2007:					
Revenues	$ 2,672	$ 2,543	$ 224	$ (1,755)	$ 3,684
Intersegment revenues	—	(1,598)	(157)	1,755	—
Total revenues	$ 2,672	$ 945	$ 67	$ —	$ 3,684
Income before income taxes	$ 1,227	$ 18	$ 66	$ (59)	$ 1,252
As of June 30, 2008:					
Total assets	$ 35,885	$ 2,879	$ 570	$ (1,311)	$ 38,023
As of December 31, 2007:					
Total assets	$ 29,317	$ 1,759	$ 487	$ (829)	$ 30,734

8. Divestitures

On May 1, 2008, we sold certain long-lived producing assets in Texas, Oklahoma and Kansas in a volumetric production payment transaction for net proceeds of $616 million. These assets had estimated proved reserves of approximately 94 bcfe and current net production (at the time of sale) of approximately 47 mmcfe per day. Chesapeake retained drilling rights on the properties below currently producing intervals. For accounting purposes, the transaction was treated as a sale and the company's proved reserves were reduced accordingly.

In the Current Period, we sold non-core natural gas and oil assets in the Rocky Mountains and in the Arkoma Basin Woodford Shale play for proceeds of $243 million.

9. Fair Value Measurements

Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2008.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in millions)			
Financial Assets (Liabilities):				
Derivatives	$ —	$ (1,568)	$ (5,060)	$ (6,628)
Investments	$ 87	$ —	$ —	$ 87
Other long-term assets	$ 23	$ —	$ —	$ 23
Long-term debt	$ —	$ —	$ (3,781)	$ (3,781)
Other long-term liabilities	$ (23)	$ —	$ —	$ (23)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements

Investments. The fair value of Chesapeake's investment in Gastar Exploration Ltd. common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of our Deferred Compensation Plan, is based on quoted market prices.

Level 2 Fair Value Measurements

Derivatives. The fair values of our natural gas swaps are measured internally using established index prices and other sources. These values are based upon, among other things, futures prices and time to maturity.

Level 3 Fair Value Measurements

Derivatives. The fair values of our derivatives, excluding natural gas swaps, are based on estimates provided by our respective counterparties and reviewed internally using established index prices and other sources. These values are based upon, among other things, futures prices, interest rate curves and time to maturity.

Debt. The fair value of our long-term debt is based on face value of the debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A reconciliation of Chesapeake's assets and liabilities classified as Level 3 measurements is presented below.

	Derivatives	Debt	Total
		($ in millions)	
Balance of Level 3 as of January 1, 2008	$ (340)	$ (2,404)	$ (2,744)
Total gains or losses (realized/unrealized):			
Included in earnings[a]	(4,180)	(127)	(4,307)
Included in other comprehensive income (loss)	(51)	—	(51)
Purchases, issuances and settlements	(489)	(1,250)[b]	(1,739)
Transfers in and out of Level 3	—	—	—
Balance of Level 3 as of June 30, 2008	$ (5,060)	$ (3,781)	$ (8,841)

(a)

	Natural Gas and Oil Revenue	Interest
	($ in millions)	
Total gains and losses related to derivatives included in earnings for the period	$ (4,245)	$ 65
Change in unrealized gains or losses relating to assets still held at reporting date	$ (4,405)	$ 69

(b) Amount represents debt now recorded at fair value as a result of new interest rate swaps entered into in the Current Period.

10. Recently Issued and Proposed Accounting Standards

The FASB recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Since we have not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements – an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact that adoption of this statement will have on our financial position, results of operations or cash flows.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement).* FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, Accounting for Convertible Debt and Debt issued with Stock Purchase Warrants. The accounting prescribed by FSP APB 14-1 would increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers will have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. We are currently assessing the impact that adoption of this staff position will have on our consolidated financial position, results of operations or cash flows.

11. Subsequent Events

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company to develop our Haynesville Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, Plains acquired a 20% interest in our approximately 550,000 net acres of Haynesville Shale leasehold for $1.65 billion in cash, consisting of $1.375 billion paid on July 7, 2008 with the remainder to be paid by October 30, 2008, subject to normal post-closing adjustments. Plains has also agreed to fund 50% of our 80% share of the costs associated with drilling and completing future Haynesville Shale joint venture wells over a multi-year period, up to an additional $1.65 billion. In addition, Plains has the right to a 20% participation in any additional leasehold we acquire in the Haynesville Shale. We used approximately $1.1 billion of the proceeds from this transaction to temporarily repay outstanding indebtedness under our revolving bank credit facility and the balance to pay for leasehold acquisition and drilling costs in the Haynesville Shale play and for other general corporate purposes. Proceeds from the sale will be reflected as a reduction of natural gas and oil properties for accounting purposes, with no gain or loss recognized.

On July 7, 2008, we redeemed the outstanding principal amount of $300 million of our 7.75% Senior Notes due 2015 for $312 million. We will recognize a $31 million loss associated with this transaction in the third quarter of 2008.

On July 15, 2008, we completed a public offering of 28.75 million shares of common stock at $57.25 per share. Net proceeds of approximately $1.586 billion were used to repay outstanding borrowings under our revolving bank credit facility, which may be reborrowed to fund our drilling and leasehold acquisition initiatives and for other general corporate purposes.

On August 8, 2008, BP America Inc. acquired all of our interests in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play for $1.75 billion in cash. The properties, which are located in Atoka, Coal, Hughes and Pittsburg counties, Oklahoma, are currently producing approximately 50 mmcfe per day.

Subsequent to June 30, 2008, a holder of our 4.5% cumulative convertible preferred stock exchanged 891,100 shares for 2,227,750 shares of common stock in a privately negotiated exchange. This will result in a $12 million loss on conversion of preferred stock in the third quarter of 2008.

Subsequent to June 30, 2008, holders of our 5.0% (Series 2005B) cumulative convertible preferred stock exchanged 935,885 shares for 2,662,940 shares of common stock in privately negotiated exchanges. This will result in a $13 million loss on conversion of preferred stock in the third quarter of 2008.

On August 1, 2008, we completed a volumetric production payment transaction with estimated proved reserves of approximately 93 bcfe and current net production (at the time of sale) of approximately 46 mmcfe per day from wells in the Anadarko Basin of Oklahoma. This transaction resulted in net proceeds to us of $600 million.

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, natural gas and oil sales, average sales prices received, other operating income and expenses for the three and six months ended June 30, 2008 (the "Current Quarter" and the "Current Period") and the three and six months ended June 30, 2007 (the "Prior Quarter" and the "Prior Period"):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Net Production:				
Natural gas (mmcf)	194,994	156,080	382,766	296,872
Oil (mbbls)	2,816	2,324	5,562	4,467
Natural gas equivalent (mmcfe)	211,890	170,024	416,138	323,674
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 1,896	$ 1,059	$ 3,329	$ 1,947
Natural gas derivatives – realized gains (losses)	(302)	185	(34)	600
Natural gas derivatives – unrealized gains (losses)	(2,526)	167	(3,528)	(131)
Total natural gas sales	(932)	1,411	(233)	2,416
Oil sales	337	140	596	253
Oil derivatives – realized gains (losses)	(121)	12	(174)	30
Oil derivatives – unrealized gains (losses)	(878)	(15)	(1,010)	(27)
Total oil sales	(662)	137	(588)	256
Total natural gas and oil sales	$ (1,594)	$ 1,548	$ (821)	$ 2,672
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 9.73	$ 6.78	$ 8.70	$ 6.56
Oil ($ per bbl)	$ 119.81	$ 60.10	$ 107.13	$ 56.60
Natural gas equivalent ($ per mcfe)	$ 10.54	$ 7.05	$ 9.43	$ 6.80
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 8.18	$ 7.97	$ 8.61	$ 8.58
Oil ($ per bbl)	$ 76.96	$ 65.37	$ 75.86	$ 63.34
Natural gas equivalent ($ per mcfe)	$ 8.55	$ 8.21	$ 8.93	$ 8.74
Other Operating Income[(a)] ($ in millions):				
Natural gas and oil marketing	$ 24	$ 19	$ 46	$ 34
Service operations	$ 8	$ 11	$ 15	$ 23
Other Operating Income ($ per mcfe):				
Natural gas and oil marketing	$ 0.12	$ 0.11	$ 0.11	$ 0.10
Service operations	$ 0.04	$ 0.07	$ 0.04	$ 0.07
Expenses ($ per mcfe):				
Production expenses	$ 1.03	$ 0.90	$ 1.01	$ 0.91
Production taxes	$ 0.41	$ 0.31	$ 0.39	$ 0.29
General and administrative expenses	$ 0.48	$ 0.32	$ 0.43	$ 0.33
Natural gas and oil depreciation, depletion and amortization	$ 2.47	$ 2.60	$ 2.49	$ 2.58
Depreciation and amortization of other assets	$ 0.19	$ 0.23	$ 0.18	$ 0.23
Interest expense[(b)]	$ 0.36	$ 0.54	$ 0.39	$ 0.52
Interest Expense ($ in millions):				
Interest expense	$ 81	$ 91	$ 168	$ 166
Interest rate derivatives – realized (gains) losses	(4)	—	(4)	2
Interest rate derivatives – unrealized (gains) losses	(14)	(7)	(1)	(6)
Total interest expense	$ 63	$ 84	$ 163	$ 162
Net Wells Drilled	485	489	933	950
Net Producing Wells as of the End of the Period	22,324	20,136	22,324	20,136

(a) Includes revenue and operating costs.

(b) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized.

We are the largest producer of natural gas in the United States. We own interests in approximately 40,200 producing natural gas and oil wells that are currently producing approximately 2.3 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S., east of the Rocky Mountains.

Our most important operating area has historically been the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At June 30, 2008, 46% of our estimated proved natural gas and oil reserves were located in the Mid-Continent region. However, during the past five years, we have established a top-three position in nearly every major unconventional play onshore in the U.S., including the Barnett Shale in the *Fort Worth Basin* in north-central Texas; the Haynesville Shale in the *Ark-La-Tex* area of East Texas and northern Louisiana; the Fayetteville Shale in the *Arkoma Basin* of Arkansas; and the Marcellus and Lower Huron Shales in the *Appalachian Basin* of Kentucky, West Virginia, Pennsylvania and New York. In addition, we are pursuing other unconventional plays in the *Anadarko Basin* of western Oklahoma, the *Ardmore Basin* of southern Oklahoma, the *Arkoma Basin* of eastern Oklahoma and the *Permian and Delaware Basins* of West Texas and eastern New Mexico.

Natural gas and oil production for the Current Quarter was 211.9 bcfe, an increase of 41.9 bcfe, or 25% over the 170.0 bcfe produced in the Prior Quarter. The Current Quarter marked the 28th consecutive quarter we have increased our production. During these 28 quarters, Chesapeake's U.S. production has increased 488%, for an average compound quarterly growth rate of 6.5% and an average compound annual growth rate of 29%.

During the Current Period, Chesapeake continued the industry's most active drilling program and drilled 988 gross (837 net) operated wells and participated in another 856 gross (95 net) wells operated by other companies. The company's drilling success rate was 99% for company-operated wells and 96% for non-operated wells. Also during the Current Period, we invested $2.486 billion in operated wells (using an average of 143 operated rigs) and $371 million in non-operated wells (using an average of 104 non-operated rigs) for total drilling, completing and equipping costs of $2.857 billion.

Chesapeake began 2008 with estimated proved reserves of 10.879 tcfe and ended the Current Period with 12.170 tcfe, an increase of 1.291 tcfe, or 12%. During the Current Period, we replaced 416 bcfe of production with an internally estimated 1.707 tcfe of new proved reserves, for a reserve replacement rate of 410%. Reserve replacement through the drillbit was 1.751 tcfe, or 421% of production, including 779 bcfe of positive performance revisions and 182 bcfe of positive revisions resulting from natural gas and oil price increases between December 31, 2007 and June 30, 2008. Reserve replacement through the acquisition of proved reserves was 85 bcfe. During the Current Period, we divested 129 bcfe of estimated proved reserves. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2008 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Since 2000, Chesapeake has invested $12.2 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (14.9 million net acres) and 3-D seismic (20.8 million acres) in the U.S. On this leasehold, the company has approximately 34,000 net drillsites representing more than a 10-year inventory of drilling projects.

As of June 30, 2008, the company's debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 57% compared to 47% as of December 31, 2007. The average maturity of our long-term debt is over eight years with an average interest rate of approximately 5.5%.

Business Strategy

As a result of successful drilling results, in March 2008, we began accelerating our leasehold acquisition in the Haynesville Shale as well as continuing our active leasing and drilling programs in the Barnett, Fayetteville and Marcellus Shale plays. Our current budgeted capital expenditures for drilling, leasehold and producing property acquisitions, geophysical costs, and additions to midstream, compression and other property and equipment are $16.3 billion to $17.5 billion in 2008 and $9.2 billion to $10.3 billion in 2009. To help fund these expenditures and develop the acreage we have acquired, we have brought in a joint venture partner for a promoted 20% interest in the Haynesville Shale and anticipate bringing in 25% joint venture partners for the Fayetteville and Marcellus Shale plays on a promoted basis as well. These joint ventures will allow us to recover most or all of our initial leasehold investments in these plays, reduce our ongoing capital costs and help diminish future risks.

Since March 31, 2008, as detailed below, we have completed transactions that have provided approximately $9.4 billion of additional capital to fund our increased capital expenditures. In each case, we used the proceeds to temporarily repay outstanding indebtedness under our revolving bank credit facility, which we reborrow from time to time to fund capital expenditures, and for other general corporate purposes, including the redemption of our 7.75% Senior Notes due 2015.

On April 2, 2008, we issued 23 million shares of our common stock in a public offering at a price of $45.75 per share, and on May 20, 2008, we completed public offerings of $800 million of our 7.25% Senior Notes due 2018 and $1.380 billion of our 2.25% Contingent Convertible Senior Notes due 2038. These three offerings resulted in aggregate net proceeds to us of approximately $3.147 billion. Additionally, on July 15, 2008, we issued 28.75 million shares of our common stock in a public offering at a price of $57.25 per share. We received net proceeds of approximately $1.586 billion. The July common stock offering was intended as a substitute for the capital previously expected to be raised through the sale of a minority interest in a private partnership for our midstream assets. We determined not to pursue this transaction at that time, which was anticipated to result in net proceeds to us of approximately $1.0 billion, but we continue to evaluate various options to monetize our midstream assets.

On May 1, 2008, we completed a volumetric production payment (VPP) transaction involving approximately 94 bcfe of estimated proved reserves and current net production (at the time of sale) of approximately 47 mmcfe per day from wells in Texas, Oklahoma and Kansas. This transaction resulted in net proceeds to us of $616 million.

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company to develop our Haynesville Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, Plains acquired a 20% interest in our approximately 550,000 net acres of Haynesville Shale leasehold for an aggregate of $1.65 billion in cash, consisting of $1.375 billion paid on July 7, 2008 with the remainder to be paid by October 30, 2008, subject to customary post-closing adjustments. Plains has also agreed to fund 50% of our 80% share of the costs associated with drilling and completing future Haynesville Shale joint venture wells over a multi-year period, up to an additional $1.65 billion. In addition, Plains will have the right to a 20% participation in any additional leasehold we acquire in the Haynesville Shale.

On August 1, 2008, we completed a VPP transaction with estimated proved reserves of approximately 93 bcfe and current net production (at the time of sale) of approximately 46 mmcfe per day from wells in the Anadarko Basin in Oklahoma. This transaction resulted in net proceeds to us of $600 million. This was our third VPP transaction and we expect to raise additional capital by this means in 2009.

On August 8, 2008, BP America Inc. acquired all of our interests in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play for $1.75 billion in cash. The properties, which are located in Atoka, Coal, Hughes and Pittsburg counties, Oklahoma, are currently producing approximately 50 mmcfe per day.

We anticipate that our 2008 and 2009 budgeted exploration and development capital expenditures, together with our operating costs and other capital expenditure requirements, will exceed our cash flow from operations and our borrowing capacity under our revolving credit facility. To provide for our anticipated cash requirements, we expect to engage in additional monetization transactions, including sales of undeveloped acreage and non-strategic assets and additional joint venture arrangements. While we believe that some or all of these sources of liquidity will continue to be available to us, we would be required to curtail our capital spending if we were unable to access sufficient cash to fund our capital spending and operations.

Management believes that our planned leasehold and development joint ventures and various asset monetization programs benefit the company in several ways. We will be able to improve our asset base, reduce our financial risk, decrease our DD&A rate and increase our profitability per unit of production, thereby increasing our returns on capital and advancing future value creation to the present.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund operating expenses and capital expenditures. Cash provided by operating activities was $2.754 billion in the Current Period compared to $2.122 billion in the Prior Period. The $632 million increase in the Current Period was primarily due to higher natural gas and oil prices and higher volumes of natural gas and oil production. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. While a decline in natural gas or oil prices would affect the amount of cash flow that would be generated from operations, we currently have natural gas and oil hedges in place covering 96% of our expected remaining natural gas production in 2008 and 99% of our expected remaining oil production in 2008, thereby minimizing the commodity price risk associated with almost all of our 2008 cash flow. Our natural gas and oil hedges as of June 30, 2008 are detailed in Item 3 of Part I of this report. Depending on changes in natural gas and oil futures markets and management's view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

Extreme volatility in natural gas and oil prices in 2008 has created wide swings in the mark-to-market value of our natural gas and oil derivatives. As of June 30, 2008, we had a net natural gas and oil derivative liability of $6.551 billion as a result of significant increases in natural gas and oil prices since December 31, 2007. Of this amount, $3.367 billion was classified as a current liability and was largely responsible for our $4.1 billion working capital deficit at June 30, 2008. Subsequent to June 30, 2008, natural gas and oil prices have decreased significantly causing our natural gas and oil hedges to move in our favor. Should prices on September 30, 2008 be the same as current prices, we believe substantially all of the 2008 unrealized loss on natural gas and oil derivatives would be reversed and reported as an unrealized gain in the 2008 third quarter. We satisfy commodity derivative liabilities from a portion of the proceeds of natural gas and oil production sold at market prices during the period of contract settlement (which will occur through 2022). We have arrangements with our hedging counterparties that allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil hedges by making collateral allocations from our bank credit facility or directly pledging natural gas and oil properties, rather than posting cash or letters of credit with the counterparties.

Our $3.5 billion bank credit facility is another source of liquidity. At August 8, 2008, there was $1.744 billion of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $6.758 billion and repaid $6.195 billion in the Current Period, and we borrowed $3.544 billion and repaid $2.624 billion in the Prior Period.

On April 2, 2008 we issued 23 million shares of our common stock in a public offering at a price of $45.75 per share, and on May 20, 2008 we completed public offerings of $800 million of our 7.25% Senior Notes due 2018 and $1.380 billion of our 2.25% Contingent Convertible Senior Notes due 2038. These three offerings resulted in aggregate net proceeds to us of approximately $3.147 billion, which we used to fund the redemption of our 7.75% Senior Notes due 2015 and to temporarily repay indebtedness outstanding under our revolving bank credit facility. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Six Months Ended June 30,			
	2008		2007	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Common stock	$ 1,052	$ 1,011	$ —	$ —
Contingent convertible unsecured senior notes	1,380	1,349	1,150	1,124
Unsecured senior notes guaranteed by subsidiaries	800	787	—	—
Total	$ 3,232	$ 3,147	$ 1,150	$ 1,124

In May 2008, we sold a portion of our proved reserves in certain producing assets in Texas, Oklahoma and Kansas in a VPP transaction for proceeds of approximately $616 million, net of transaction costs.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities for the Current Period and the Prior Period. We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

We paid dividends on our common stock of $66 million and $54 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. Dividends paid on our preferred stock decreased to $22 million in the Current Period from $52 million in the Prior Period as a result of conversions and exchanges of preferred stock into common stock during 2007 and the Current Period. We received $7 million and $6 million from the exercise of employee and director stock options in the Current Period and the Prior Period, respectively.

In the Current Period and Prior Period, we paid $93 million and $52 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

On January 1, 2006, we adopted SFAS 123(R), which requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In the Current Period and the Prior Period, we reported a tax benefit from stock-based compensation of $21 million and $8 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased $47 million in the Current Period and decreased $10 million in the Prior Period. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers. Recently there have been concerns about the ability of certain investment banks to continue to meet their financial obligations. We monitor our counterparties and do not believe a failure by an investment bank counterparty would have a material negative impact on our liquidity.

Our accounts receivable are primarily from purchasers of natural gas and oil ($1.325 billion at June 30, 2008) and exploration and production companies which own interests in properties we operate ($187 million at June 30, 2008). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parental guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Additionally, we are exposed to credit risk associated with the indemnification provided by NiSource Inc. related to the litigation discussed in Note 3 to the financial statements included in Part I of this report.

Investing Activities

Cash used in investing activities increased to $6.329 billion during the Current Period, compared to $4.003 billion during the Prior Period. We have continued our active drilling program and our acquisitions are focused on leasehold and property acquisitions needed for planned natural gas and oil development. Our investing activities during the Current Period and the Prior Period reflect our increasing focus on converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential, and investing in drilling rigs, midstream systems, compressors and other property and equipment to support our natural gas and oil exploration, development and production activities. The following table shows our cash used in (provided by) investing activities during these periods:

	Six Months Ended June 30,	
	2008	2007
Natural Gas and Oil Investing Activities:	($ in millions)	
Exploration and development of natural gas and oil properties	$ 2,785	$ 2,185
Acquisition of leasehold and unproved properties	2,645	957
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	202	327
Geological and geophysical costs	150	134
Interest on leasehold and unproved properties	168	118
Proceeds from sale of volumetric production payment	(616)	—
Divestitures of proved and unproved properties and leasehold	(247)	—
Deposits for acquisitions	19	5
Total natural gas and oil investing activities	5,106	3,726
Other Investing Activities:		
Additions to other property and equipment	1,229	484
Proceeds from sale of drilling rigs and equipment	(34)	(87)
Proceeds from sale of compressors	(51)	—
Additions to (proceeds from) investments	81	(112)
Sale of other assets	(2)	(8)
Total other investing activities	1,223	277
Total cash used in investing activities	$ 6,329	$ 4,003

Bank Credit and Hedging Facilities

We have a $3.5 billion syndicated revolving bank credit facility that matures in November 2012. As of June 30, 2008, we had $2.513 billion in outstanding borrowings under this facility and had utilized approximately $6 million of the facility for various letters of credit. Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), plus a margin that varies from 0.75% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. Our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake and all its other wholly-owned subsidiaries except minor subsidiaries are guarantors.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.57 to 1 and our indebtedness to EBITDA ratio was 2.05 to 1 at June 30, 2008. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

We have six secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet any additional collateral coverage requirements. The hedging facilities are subject to an annual exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time. The fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities [a]					
	#1	**#2**	**#3**	**#4**	**#5**	**#6**
			($ in millions)			
Fair value of outstanding transactions, as of June 30, 2008	$ (214)	$ (1,832)	$ (1,181)	$ (181)	$ (273)	$ (760)
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2020	2012	2012	2012

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 – 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 – 6.

Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of June 30, 2008, senior notes represented approximately $11.1 billion of our total debt and consisted of the following ($ in millions):

7.5% Senior Notes due 2013	364
7.625% Senior Notes due 2013	500
7.0% Senior Notes due 2014	300
7.5% Senior Notes due 2014	300
6.375% Senior Notes due 2015	600
7.75% Senior Notes due 2015[a]	300
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.25% Euro-denominated Senior Notes due 2017 [b]	945
6.5% Senior Notes due 2017	1,100
6.25% Senior Notes due 2018	600
7.25% Senior Notes due 2018	800
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035[c]	690
2.5% Contingent Convertible Senior Notes due 2037[c]	1,650
2.25% Contingent Convertible Senior Notes due 2038[c]	1,380
Discount on senior notes	(100)
Impact of interest rate derivatives[d]	(8)
Total notes payable and long term debt	11,191
Less current maturities of long-term debt[c]	(690)
Total notes payable and long-term debt net of current maturities	$ 10,501

(a) The 7.75% Senior Notes due 2015 were redeemed on July 7, 2008.

(b) The principal amount shown is based on the dollar/euro exchange rate of $1.5748 to €1.00 as of June 30, 2008. See Note 2 of our accompanying condensed consolidated financial statements for information on our related cross currency swap.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is that the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the second quarter of 2008, the price of our common stock exceeded the threshold level for the 2.75% Contingent Convertible Senior Notes due 2035 during the specified period and, as a result, the holders of our 2.75% Contingent Convertible Senior Notes have the option to convert their notes into cash and common stock in the third quarter of 2008. While our 2.75% Contingent Convertible Senior Notes are classified as current debt in our balance sheet as of June 30, 2008, based on current trading prices for the notes, holders currently would realize greater value by selling their notes in the open market as opposed to converting them into cash and common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$48.83	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$64.477	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$107.36	June 14, 2019

(d) See Note 2 for discussion related to these instruments.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at June 30, 2008. These include commitments related to drilling rig and compressor leases, transportation and drilling contracts and lending and guarantee agreements. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in Part I of this report.

Union Contract

As a result of the CNR acquisition, we assumed a collective bargaining agreement with the United Steel Workers of America ("USWA") which expired effective December 1, 2006, covering approximately 145 of our field employees in West Virginia and Kentucky. We continued to operate under the terms of the collective bargaining agreement while negotiating with the USWA. Contract negotiations began in October 2006 and have been mediated by the Federal Mediation and Conciliation Service. On May 4, 2007, we presented the USWA leadership our "last, best and final offer". On December 7, 2007, the USWA membership voted to reject our offer. The company declared impasse and, effective February 1, 2008, we implemented the terms of our offer with certain minor clarifications. On March 12, 2008, the USWA filed an Unfair Labor Practice Charge with the National Labor Relations Board ("NLRB"). The Regional Director in Cincinnati found that the company committed no unfair labor practices. The Union has appealed this decision and we are awaiting the outcome from the NLRB. There have been no strikes, work stoppages or slowdowns since the expiration of the contract, although no assurances can be given that such actions will not occur.

Results of Operations – Three Months Ended June 30, 2008 vs. June 30, 2007

General. For the Current Quarter, Chesapeake had a net loss of $1.597 billion, or $3.17 per diluted common share, on total revenues of ($455) million. This compares to net income of $518 million, or $1.01 per diluted common share, on total revenues of $2.105 billion during the Prior Quarter. The Current Quarter loss is due to an unrealized non-cash after-tax mark-to-market loss of $2.094 billion related to future period natural gas and oil hedges resulting primarily from higher natural gas and oil prices as of June 30, 2008 compared to March 31, 2008.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were ($1.594) billion compared to $1.548 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 211.9 bcfe at a weighted average price of $8.55 per mcfe, compared to 170.0 bcfe produced in the Prior Quarter at a weighted average price of $8.21 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of ($3.404) billion and $152 million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $71 million and increased production resulted in a $344 million increase, for a total increase in revenues of $415 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Quarter to the Current Quarter was primarily generated from the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $8.18, compared to $7.97 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $76.96 and $65.37 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net decrease in natural gas and oil revenues of $423 million, or $2.00 per mcfe, in the Current Quarter and an increase of $197 million, or $1.16 per mcfe, in the Prior Quarter.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flow. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $19 million and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $3 million without considering the effect of derivative activities.

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

	For the Three Months Ended June 30,			
	2008		2007	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[(a)]	107,691	51%	91,134	54%
Barnett Shale	43,311	20	19,046	11
Permian and Delaware Basins	19,130	9	14,540	8
South Texas and Texas Gulf Coast	17,820	9	19,884	12
Ark-La-Tex	14,965	7	13,927	8
Appalachian Basin [(b)]	8,973	4	11,493	7
Total production	211,890	100%	170,024	100%

(a) The Current Quarter was impacted by the sale of 2.9 bcfe of production in a VPP transaction that closed on May 1, 2008.

(b) The Current Quarter was impacted by the sale of 4.7 bcfe of production in a VPP transaction that closed on December 31, 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in both the Current Quarter and the Prior Quarter.

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.099 billion in natural gas and oil marketing sales in the Current Quarter, with corresponding natural gas and oil marketing expenses of $1.075 billion, for a net margin before depreciation of $24 million. This compares to sales of $523 million, expenses of $504 million and a net margin before depreciation of $19 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in natural gas and oil marketing net margin related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired and leased. Chesapeake recognized $40 million in service operations revenue in the Current Quarter with corresponding service operations expense of $32 million, for a net margin before depreciation of $8 million. This compares to revenue of $34 million, expenses of $23 million and a net margin before depreciation of $11 million in the Prior Quarter. The decrease in service operations net margin is due to higher drilling costs.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $219 million in the Current Quarter compared to $153 million in the Prior Quarter. On a unit-of-production basis, production expenses were $1.03 per mcfe in the Current Quarter compared to $0.90 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. We expect that production expenses for 2008 will range from $0.95 to $1.05 per mcfe produced.

Production Taxes. Production taxes were $88 million in the Current Quarter compared to $53 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.41 per mcfe in the Current Quarter compared to $0.31 per mcfe in the Prior Quarter. The $35 million increase in production taxes in the Current Quarter is due to an increase in production of 42 bcfe and an increase in the realized average sales price of natural gas and oil of $3.49 per mcfe (excluding gains or losses on derivatives).

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for 2008 to range from $0.45 to $0.50 per mcfe based on NYMEX prices ranging from $9.50 to $10.50 per mcf of natural gas and oil prices of $105.00 per barrel.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $101 million in the Current Quarter and $54 million in the Prior Quarter. General and administrative expenses were $0.48 and $0.32 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of the company’s continued growth as well as increased civic contributions, media activities and increased litigation accurals. Included in general and administrative expenses is stock-based compensation of $21 million and $12 million for the Current Quarter and Prior Quarter, respectively. This increase was mainly due to a higher number of unvested restricted shares outstanding during the Current Quarter and a higher stock price at the time of new grants. We anticipate that general and administrative expenses for 2008 will be between $0.43 and $0.49 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.12 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

The discussion of stock-based compensation in Note 5 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil 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 $83 million and $59 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $523 million and $442 million during the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.47 and $2.60 in the Current Quarter and in the Prior Quarter, respectively. The $0.13 decrease in the average DD&A rate is the result of our underlying reserve base growing faster than our capitalized costs and related future development costs and the monetization of natural gas and oil properties. We expect the DD&A rate for 2008 to be between $2.30 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $40 million in both the Current Quarter and the Prior Quarter. Depreciation and amortization of other assets was $0.19 and 0.23 per mcfe for the Current Quarter and the Prior Quarter, respectively. The decrease per mcfe in the Current Quarter was primarily due to higher production volume. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect 2008 depreciation and amortization of other assets to be between $0.20 and $0.24 per mcfe produced.

Interest and Other Income (Expense). Interest and other income (expense) was ($1) million in the Current Quarter compared to $1 million in the Prior Quarter. The Current Quarter consisted of $2 million of interest income, ($5) million related to equity investments and $2 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, ($2) million related to equity investments and $1 million of miscellaneous income.

Interest Expense. Interest expense decreased to $63 million in the Current Quarter compared to $84 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2008	2007
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 168	$ 147
Capitalized interest	(94)	(61)
Realized (gain) loss on interest rate derivatives	(4)	—
Unrealized (gain) loss on interest rate derivatives	(14)	(7)
Amortization of loan discount and other	7	5
Total interest expense	$ 63	$ 84
Average long-term borrowings	$ 10,064	$ 7,899

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.36 per mcfe in the Current Quarter compared to $0.54 in the Prior Quarter. The decrease in interest expense per mcfe is due to increased production volumes and an increase in capitalized interest. We expect interest expense for 2008 to be between $0.45 and $0.50 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investments. In the Prior Quarter, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $126 million and a gain of $83 million.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $1 billion in the Current Quarter, compared to income tax expense of $318 million in the Prior Quarter. Of the $1.318 billion decrease in the Current Quarter, $1.305 billion was the result of the decrease in net income before income taxes and $13 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Quarter and 38% in the Prior Quarter. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Results of Operations – Six Months Ended June 30, 2008 vs. June 30, 2007

General. For the Current Period, Chesapeake had a net loss of $1.729 billion, or $3.54 per diluted common share, on total revenues of $1.156 billion. This compares to net income of $776 million, or $1.51 per diluted common share, on total revenues of $3.684 billion during the Prior Period. The Current Period loss is due to an unrealized non-cash after-tax mark-to-market loss of $2.791 billion related to future period natural gas and oil hedges resulting primarily from higher natural gas and oil prices as of June 30, 2008 compared to December 31, 2007.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were ($821) million compared to $2.672 billion in the Prior Period. In the Current Period, Chesapeake produced 416.1 bcfe at a weighted average price of $8.93 per mcfe, compared to 323.7 bcfe produced in the Prior Period at a weighted average price of $8.74 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of ($4.538) billion and ($158) million in the Current Period and Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $78 million and increased production resulted in a $808 million increase, for a total increase in revenues of $886 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Period to the Current Period was primarily generated from the drillbit.

For the Current Period, we realized an average price per mcf of natural gas of $8.61, compared to $8.58 in the Prior Period (weighted average prices for both periods discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $75.86 and $63.34 in the Current Period and Prior Period, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net decrease in natural gas and oil revenues of $208 million, or $0.50 per mcfe, in the Current Period and a net increase of $630 million, or $1.95 per mcfe, in the Prior Period.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flow. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $38 million and $37 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $6 million and $5 million, respectively, without considering the effect of derivative activities.

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

	For the Six Months Ended June 30,			
	2008		2007	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[a]	213,619	51%	172,838	53%
Barnett Shale	81,285	20	35,201	11
Permian and Delaware Basins	38,926	9	27,248	9
South Texas and Texas Gulf Coast	36,709	9	39,027	12
Ark-La-Tex	28,742	7	26,787	8
Appalachian Basin [b]	16,857	4	22,573	7
Total production	416,138	100%	323,674	100%

(a) The Current Period was impacted by the sale of 2.9 bcfe of production in a VPP transaction that closed on May 1, 2008.
(b) The Current Period was impacted by the sale of 9.3 bcfe of production in a VPP transaction that closed on December 31, 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in both the Current Period and the Prior Period.

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.895 billion in natural gas and oil marketing sales in the Current Period, with corresponding natural gas and oil marketing expenses of $1.849 billion, for a net margin before depreciation of $46 million. This compares to sales of $945 million, expenses of $911 million and a net margin before depreciation of $34 million in the Prior Period. In the Current Period, Chesapeake realized an increase in natural gas and oil marketing net margin related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired and leased. Chesapeake recognized $82 million in service operations revenue in the Current Period with corresponding service operations expense of $67 million, for a net margin before depreciation of $15 million. This compares to revenue of $67 million, expenses of $44 million and a net margin before depreciation of $23 million in the Prior Period. The decrease in service operations net margin is due to higher drilling costs.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $419 million in the Current Period compared to $295 million in the Prior Period. On a unit-of-production basis, production expenses were $1.01 per mcfe in the Current Period compared to $0.91 per mcfe in the Prior Period. The increase in the Current Period was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. We expect that production expenses for 2008 will range from $0.95 to $1.05 per mcfe produced.

Production Taxes. Production taxes were $163 million in the Current Period compared to $95 million in the Prior Period. On a unit-of-production basis, production taxes were $0.39 per mcfe in the Current Period compared to $0.29 per mcfe in the Prior Period. The $68 million increase in production taxes in the Current Period is due to an increase in production of 92 bcfe and an increase in the realized average sales price of natural gas and oil of $2.63 per mcfe (excluding gains or losses on derivatives).

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for 2008 to range from $0.45 to $0.50 per mcfe based on NYMEX prices ranging from $9.50 to $10.50 per mcf of natural gas and oil prices of $105.00 per barrel.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $180 million in the Current Period and $107 million in the Prior Period. General and administrative expenses were $0.43 and $0.33 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of the company's continued growth as well as increased civic contributions, media activities and increased litigation accurals. Included in general and administrative expenses is stock-based compensation of $40 million and $22 million for the Current Period and Prior Period, respectively. This increase was mainly due to a higher number of unvested restricted shares outstanding during the Current Period and a higher stock price at the time of new grants. We anticipate that general and administrative expenses for 2008 will be between $0.43 and $0.49 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.12 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

The discussion of stock-based compensation in Note 5 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil 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 $167 million and $110 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.038 billion and $835 million during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.49 and $2.58 in the Current Period and in the Prior Period, respectively. The $0.09 decrease in the average DD&A rate is the result of our underlying reserve base growing faster than our capitalized costs and related future development costs and the monetization of natural gas and oil properties. We expect the DD&A rate for 2008 to be between $2.30 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $77 million in the Current Period and $76 million in the Prior Period. Depreciation and amortization of other assets was $0.18 and 0.23 per mcfe for the Current Period and the Prior Period, respectively. The decrease per mcfe in the Current Period was primarily due to higher production volume. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect 2008 depreciation and amortization of other assets to be between $0.20 and $0.24 per mcfe produced.

Interest and Other Income (Expense). Interest and other income (expense) was ($11) million in the Current Period compared to $10 million in the Prior Period. The Current Period consisted of $4 million of interest income, ($17) million related to equity investments and $2 million of miscellaneous income. The Prior Period consisted of $4 million of interest income, $4 million related to equity investments and $2 million of miscellaneous income.

Interest Expense. Interest expense increased to $163 million in the Current Period compared to $162 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2008	2007
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 336	$ 282
Capitalized interest	(180)	(125)
Realized (gain) loss on interest rate derivatives	(4)	2
Unrealized (gain) loss on interest rate derivatives	(1)	(6)
Amortization of loan discount and other	12	9
Total interest expense	$ 163	$ 162
Average long-term borrowings	$ 9,597	$ 7,653

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.39 per mcfe in the Current Period compared to $0.52 in the Prior Period. The decrease in interest expense per mcfe is due to increased production volumes. We expect interest expense for 2008 to be between $0.45 and $0.50 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investments. In the Prior Period, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $126 million and a gain of $83 million.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $1.082 billion in the Current Period, compared to income tax expense of $476 million in the Prior Period. Of the $1.558 billion decrease in the Current Period, $1.544 billion was the result of the decrease in net income before income taxes and $14 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Period and 38% in the Prior Period. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties, income taxes and business combinations to be critical policies. These policies are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2007 ("2007 Form 10-K").

Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements* for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

As of June 30, 2008, we had a net derivative liability of $6.628 billion, of which 76% was based on estimates provided by our respective counterparties and reviewed internally using established indexes and other sources and, as such, are classified as a Level 3 fair value measurement. The accounting applicable to our natural gas and oil derivative contracts is discussed in Note 2 and Note 9 of our condensed consolidated financial statements included in Part I of this report.

Recently Issued and Proposed Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Since we have not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements – an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact that adoption of this statement will have on our financial position, results of operations or cash flows.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion, (Including Partial Cash Settlement)*. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, Accounting for Convertible Debt and Debt issued with Stock Purchase Warrants. The accounting prescribed by FSP APB 14-1 would increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers will have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. We are currently assessing the impact that adoption of this staff position will have on our consolidated financial position, results of operations or cash flows.

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 natural gas and oil reserve estimates, planned capital expenditures, the drilling of natural gas and oil wells and future acquisitions, expected natural gas and oil production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations and expected future expenses. 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 1A of our 2007 Form 10-K and include:

- the volatility of natural gas and oil prices,
- the availability of capital on an economic basis to fund our drilling program,
- our ability to replace reserves and sustain production,
- our level of indebtedness,
- the strength and financial resources of our competitors,
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures,

- uncertainties in evaluating natural gas and oil reserves of acquired properties and associated potential liabilities,
- unsuccessful exploration and development drilling,
- declines in the value of our natural gas and oil properties resulting in ceiling test write-downs,
- lower prices realized on natural gas and oil sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- lower natural gas and oil prices negatively affecting our ability to borrow,
- drilling and operating risks,
- adverse effects of governmental regulation, and
- losses possible from pending or future litigation.

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 report and our other filings 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*

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of June 30, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price 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.
- Basis protection swaps are arrangements that guarantee a price differential for natural gas or oil from a specified delivery point. For Mid-Continent basis protection swaps, which typically have negative differentials to NYMEX, 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. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.
- For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.
- For call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

- 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, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

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

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

Gains or losses from certain derivative transactions are reflected as adjustments to natural gas and oil sales on the consolidated statements of operations. Realized gains (losses) are included in natural gas and oil sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within natural gas and oil sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). The components of natural gas and oil sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	($ in millions)			
Natural gas and oil sales	$ 2,233	$ 1,199	$ 3,925	$ 2,200
Realized gains (losses) on natural gas and oil derivatives	(423)	197	(208)	630
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(3,340)	162	(4,409)	(94)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(64)	(10)	(129)	(64)
Total natural gas and oil sales	$ (1,594)	$ 1,548	$ (821)	$ 2,672

As of June 30, 2008, we had the following open natural gas and oil derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our natural gas and oil production for periods after June 2008:

	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at June 30, 2008 ($ in millions)
Natural Gas (bbtu):								
Swaps:								
Q3 2008	84,653	$ 8.72	$ —	$ —	$ —	Yes	$ —	$ (386)
Q4 2008	83,392	9.61	—	—	—	Yes	—	(347)
Q1 2009	50,479	11.20	—	—	—	Yes	—	(147)
Q2 2009	40,413	9.45	—	—	—	Yes	—	(88)
Q3 – Q4 2009	79,726	9.74	—	—	—	Yes	—	(174)
2010	101,424	9.94	—	—	—	Yes	—	(124)
2011	1,825	9.28	—	—	—	Yes	—	(2)
Other Swaps:								
Q3 2008	4,600	8.73	—	—	—	No	—	(21)
Q4 2008	4,600	8.73	—	—	—	No	—	(23)
Q1 2009[(a)]	8,100	10.54	—	—	—	No	—	(29)
Q2 2009[(a)]	8,190	9.59	—	—	—	No	—	(19)
Q3 – Q4 2009[(a)]	16,560	9.72	—	—	—	No	—	(38)
2010[(a)]	32,850	9.90	—	—	—	No	—	(64)
2011	4,500	8.73	—	—	—	No	—	(11)
Basis Protection Swaps (Mid-Continent):								
Q3 2008	36,340	—	—	—	(0.46)	No	—	56
Q4 2008	36,010	—	—	—	(0.41)	No	—	63
Q1 2009	30,600	—	—	—	(0.45)	No	—	30
Q2 2009	20,020	—	—	—	(0.28)	No	—	17
Q3 – Q4 2009	40,480	—	—	—	(0.28)	No	—	33
2011 – 2018	81,089	—	—	—	(0.67)	No	—	(6)
Basis Protection Swaps (Appalachian Basin):								
Q3 2008	5,763	—	—	—	0.33	No	—	(1)
Q4 2008	5,840	—	—	—	0.33	No	—	(1)
Q1 2009	3,849	—	—	—	0.29	No	—	(1)
Q2 2009	4,178	—	—	—	0.28	No	—	(1)
Q3 – Q4 2009	8,886	—	—	—	0.27	No	—	(1)
2010	10,199	—	—	—	0.26	No	—	(2)
2011 - 2022	12,220	—	—	—	0.25	No	—	(2)
Knockout Swaps:								
Q3 2008	67,760	9.46	6.23	—	—	No	7	(251)
Q4 2008	70,250	10.08	6.28	—	—	No	7	(256)
Q1 2009	79,200	10.46	6.30	—	—	No	5	(292)
Q2 2009	88,890	9.48	6.13	—	—	No	6	(197)
Q3 – Q4 2009	188,600	9.80	6.01	—	—	No	12	(416)
2010	171,500	10.05	6.28	—	—	No	2	(244)
2011	7,200	10.38	6.41	—	—	No	—	(11)
Call Options:								
Q3 2008	32,200	—	—	10.25	—	No	21	(95)
Q4 2008	34,030	—	—	10.39	—	No	23	(118)
Q1 2009	53,100	—	—	11.27	—	No	34	(171)
Q2 2009	50,960	—	—	11.19	—	No	33	(77)
Q3 – Q4 2009	101,210	—	—	11.21	—	No	66	(189)
2010	266,450	—	—	10.57	—	No	204	(483)
2011 - 2017	193,510	—	—	10.71	—	No	128	(293)
Collars:								
Q3 2008	1,840	—	7.50	10.20	—	Yes	—	(6)
Q4 2008	1,840	—	7.50	10.20	—	Yes	—	(7)

	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at June 30, 2008 ($ in millions)
Other Collars:								
Q3 2008	6,440	$ —	$ 8.36	$ 10.27	$ —	No	$ 6	$ (19)
Q4 2008	4,610	—	8.26	10.38	—	No	6	(16)
Q1 2009	15,750	—	5.74/8.05	11.34	—	No	3	(54)
Q2 2009	15,925	—	5.75/8.05	11.10	—	No	3	(25)
Q3 – Q4 2009	32,200	—	5.74/8.05	11.14	—	No	5	(60)
2010	25,550	—	6.00/7.71	11.46	—	No	21	(34)
2011 - 2020	113,230	—	6.00/7.19	10.31	—	No	78	(226)
Total Natural Gas							670	(4,829)
Oil (mbbls):								
Swaps:								
Q3 2008	935	67.08	—	—	—	Yes	—	(69)
Q4 2008	598	66.72	—	—	—	Yes	—	(45)
Q1 2009	135	68.02	—	—	—	Yes	—	(10)
Q2 2009	137	67.84	—	—	—	Yes	—	(10)
Q3 – Q4 2009	276	67.60	—	—	—	Yes	—	(19)
Knockout Swaps:								
Q3 2008	828	81.64	56.83	—	—	No	—	(49)
Q4 2008	1,012	81.50	57.41	—	—	No	—	(60)
Q1 2009	1,935	83.41	58.21	—	—	No	—	(111)
Q2 2009	1,957	83.37	58.21	—	—	No	—	(111)
Q3 – Q4 2009	3,956	83.29	58.21	—	—	No	—	(221)
2010	4,745	90.25	60.00	—	—	No	—	(226)
2011 - 2012	1,827	106.65	60.00	—	—	No	—	(59)
Cap-Swaps:								
Q3 2008	276	77.60	55.00	—	—	No	—	(17)
Q4 2008	276	77.60	55.00	—	—	No	—	(17)
Call Options:								
Q3 2008	644	—	—	83.57	—	No	2	(36)
Q4 2008	828	—	—	81.67	—	No	3	(48)
Q1 2009	630	—	—	146.43	—	No	3	(26)
Q2 2009	637	—	—	146.43	—	No	3	(26)
Q3 – Q4 2009	1,288	—	—	146.43	—	No	6	(52)
2010	2,555	—	—	160.71	—	No	10	(79)
2011 - 2012	7,310	—	—	185.00	—	No	—	(93)
Other Collars:								
2010	730	—	90.00/80.00	136.40	—	No	—	(16)
Total Oil							27	(1,400)
Total Natural Gas and Oil							$ 697	$ (6,229)

(a) These include options to extend existing swaps for an additional 12 months at 50,000 mmbtu/day at $8.73/mmbtu, callable by the counterparty in March 2009 and March 2010 and 40,000 mmbtu/day at $11.35/mmbtu, callable by the counterparty in December 2009.

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives remaining as of June 30, 2008:

	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at June 30, 2008 ($ in millions)
Natural Gas (bbtu):						
Swaps:						
Q3 2008	9,660	$ 4.68	$ —	$ —	Yes	$ (82)
Q4 2008	9,660	4.66	—	—	Yes	(88)
Q1 2009	4,500	5.18	—	—	Yes	(40)
Q2 2009	4,550	5.18	—	—	Yes	(29)
Q3 – Q4 2009	9,200	5.18	—	—	Yes	(60)
Collars:						
Q1 2009	900	—	4.50	6.00	Yes	(7)
Q2 2009	910	—	4.50	6.00	Yes	(5)
Q3 – Q4 2009	1,840	—	4.50	6.00	Yes	(11)
Total Natural Gas						$ (322)

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at June 30, 2008.

Based upon the market prices at June 30, 2008, we expect to transfer approximately $759 million (net of income taxes) of the loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of June 30, 2008 are expected to mature by December 31, 2022.

Additional information concerning the fair value of our natural gas and oil derivative instruments, including CNR derivatives assumed, is as follows:

	2008 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ (369)
Change in fair value of contracts	(6,349)
Fair value of contracts when entered into	(467)
Contracts realized or otherwise settled	208
Fair value of contracts when closed	426
Fair value of contracts outstanding, as of June 30	$ (6,551)

The change in the fair value of our derivative instruments since January 1, 2008 resulted from new contracts entered into, the settlement of derivatives for a realized gain (loss), as well as an increase in natural gas prices. Subsequent to June 30, 2008, natural gas and oil prices have decreased significantly causing our natural gas and oil derivatives to move in our favor. Should prices on September 30, 2008 be the same as current prices, we believe substantially all of the unrealized loss on natural gas and oil derivatives for the six months ended June 30, 2008 would be reversed and reported as an unrealized gain in the 2008 third quarter. 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 natural gas and oil as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of June 30, 2008, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity						
	2008	2009	2010	2011	2012	Thereafter	Total
	($ in billions)						
Liabilities:							
Long-term debt - fixed-rate[a]	$ 0.690	$ —	$ —	$ —	$ —	$ 10.609	$ 11.299
Average interest rate	2.8%	—	—	—	—	5.6%	5.5%
Long-term debt - variable rate	$ —	$ —	$ —	$ —	$ 2.513	$ —	$ 2.513
Average interest rate	—	—	—	—	3.5%	—	3.5%

(a) This amount does not include the discount included in long-term debt of ($100) million and the impact of interest rate derivatives of ($8) million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facility. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt's carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were $4 million, a nominal amount, $4 million and ($2) million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Unrealized gains (losses) included in interest expense were $14 million, $7 million, $1 million and $6 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

As of June 30, 2008, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:							
January 2008 – November 2020	$2,750	6.87%	6 month LIBOR plus 261 basis points	—	Yes	$ —	$ (87)
January 2008 – January 2018	$ 500	6.94%	6 month LIBOR plus 290 basis points	—	No	2	(13)
Floating to Fixed Swaps:							
August 2007 – August 2010	$ 825	4.74%	3 month LIBOR	—	No	—	(16)
Swaption:							
April 2008 – October 2008	$ 250	6.50%	—	—	No	4	(9)
Call Options:							
January 2008 – July 2010	$ 500	6.56%	—	—	No	4	(8)
Collars:							
August 2007 – August 2010	$ 800	—	—	5.37%-4.52%	No	—	(17)
						$ 10	$ (150)

In the Current Period, we sold call options on three of our interest rate swaps and received $7 million in premiums. Three options were exercised in the Current Period resulting in the termination of three interest rate swaps and one call option expired unexercised. Additionally, we sold two swaptions in the Current Period and received $6 million in premiums. One swaption was exercised resulting in a new interest swap.

In the Current Period, we closed 21 interest rate swaps for a gain totaling $56 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued €600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake €19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($945 million at June 30, 2008) using an exchange rate of $1.5748 to €1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $73 million at June 30, 2008.

ITEM 4. *Controls and Procedures*

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. At the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

No changes in Chesapeake's internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, Chesapeake's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Chesapeake is currently involved in various disputes incidental to its business operations. Certain legal actions brought by royalty owners are discussed in Item 3 of our 2007 Form 10-K. Reference also is made to "Litigation" in Note 3 of the notes to the condensed consolidated financial statements included in Part I, Item 1 of this Form 10-Q, which is incorporated herein by reference. Management is of the opinion that the final resolution of currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. ***Risk Factors***

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under "Risk Factors" in Item 1A of our 2007 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

The following table presents information about repurchases of our common stock during the three months ended June 30, 2008:

Period	Total Number of Shares Purchased[a]	Average Price Paid Per Share[a]	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[b]
April 1, 2008 through April 30, 2008	9,813	$ 50.536	—	—
May 1, 2008 through May 31, 2008	12,211	54.773	—	—
June 1, 2008 through June 30, 2008	159,342	56.767	—	—
Total	181,366	$ 56.295	—	—

(a) Includes the deemed surrender to the company of 2,718 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 178,648 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and 401(k) make-up plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of company contributions.

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

Not applicable.

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

Four matters were submitted to a vote of the shareholders at Chesapeake's annual meeting of shareholders held on June 6, 2008: the election of directors for three year terms expiring in 2011; approval of the amendment to the company's Long Term Incentive Plan covering awards of stock-based compensation to its employees, consultants and non-employee directors; ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2008; and approval of a shareholder proposal regarding annual elections of directors.

In the election of directors, Aubrey K. McClendon received 447,439,585 votes for election and 15,656,693 votes were withheld from voting for Mr. McClendon; and Don Nickles received 450,299,335 votes for election and 12,796,942 votes were withheld from voting for Senator Nickles. There were no broker non-votes for the election of directors. The other directors whose terms continue after the meeting are Richard K. Davidson, Breene M. Kerr and Charles T. Maxwell, whose terms expire in 2009, and Frank Keating, Merrill A. "Pete" Miller, Jr. and Frederick B. Whittemore, whose terms expire in 2010.

On the proposal to approve an amendment of the Long Term Incentive Plan, 333,334,732 votes were received for approval of the amendment, 43,073,410 votes were received against approval of the amendment and holders of 4,140,800 shares abstained from voting on this proposal. There were 82,547,336 broker non-votes on this proposal.

On the proposal to ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2008, 453,607,962 votes were received for approval of the ratification, 5,619,212 votes were received against the ratification and holders of 3,869,103 shares abstained from voting on this proposal. There were no broker non-votes for this proposal.

On the shareholder proposal regarding annual election of directors, 231,525,541 votes were received for the proposal, 144,214,452 votes were received against the proposal and holders of 4,808,948 shares abstained from voting on this proposal. There were 82,547,337 broker non-votes on this proposal.

Item 5. ***Other Information***

Not applicable.

Item 6. ***Exhibits***

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

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1.1	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/09/2006	
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.					X
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).					X
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	10-K	001-13726	3.1.5	02/29/2008	
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.					X
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock, as amended.	10-K	001-13726	3.1.7	02/29/2008	
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.1	06/13/2007	
4.16	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company N.A., as Trustee, with respect to 7.25% senior notes due 2018.	8-K	001-13726	4.1	05/29/2008	
4.17	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company N.A., as Trustee, with respect to 2.25% contingent convertible senior notes due 2038.	8-K	001-13726	4.2	05/29/2008	
10.1.5	Chesapeake's 1999 Stock Option Plan, as amended.					X
10.1.6	Chesapeake's 2000 Employee Stock Option Plan, as amended					X
10.1.8	Chesapeake's 2001 Stock Option Plan, as amended.					X
10.1.10	Chesapeake's 2001 Nonqualified Stock Option Plan, as amended.					X
10.1.11	Chesapeake's 2002 Stock Option Plan, as amended.					X
10.1.12	Chesapeake's 2002 Non-Employee Director Stock Option Plan, as amended.					X
10.1.13	Chesapeake's 2002 Nonqualified Stock Option Plan, as amended.					X
10.1.18	Chesapeake's Amended and Restated Long Term Incentive Plan.	S-8	333-151762	99.1	06/18/2008	
10.2.1	Amended and Restated Employment Agreement dated as of January 1, 2008 between Chesapeake Energy Corporation and Aubrey K. McClendon.					X
10.4	Non-Employee Director Compensation					X
10.5	Executive Officer Compensation					X
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) 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 of the Board and Chief Executive Officer

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

Date: August 11, 2008