CHESAPEAKE ENERGY CORP
Form 10-Q
November 09, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2007

¨ Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

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

(405) 848-8000

Registrant s telephone number, including area code

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

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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 November 7, 2007, there were 473,949,071 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2007

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2007	December 31, 2006
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 3
Accounts receivable	876	845
Short-term derivative instruments	290	225
Inventory and other	112	81
Total Current Assets	1,280	1,154
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	27,226	21,949
Unevaluated properties	5,065	3,797
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(6,595)	(5,292)
Total oil and natural gas properties, at cost based on full-cost accounting	25,696	20,454
Other property and equipment:		
Natural gas gathering systems	922	552
Buildings and land	729	429
Drilling rigs	102	301
Natural gas compressors	42	127
Other	327	241
Less: accumulated depreciation and amortization of other property and equipment	(270)	(200)
Total Other Property and Equipment	1,852	1,450
Total Property and Equipment	27,548	21,904
OTHER ASSETS:		
Investments	618	699
Long-term derivative instruments	75	339
Other assets	368	321
Total Other Assets	1,061	1,359
TOTAL ASSETS	$ 29,889	$ 24,417

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	September 30, 2007	December 31, 2006
	($ in millions)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 979	$ 860
Accrued liabilities	706	419
Short-term derivative instruments	186	112
Revenues and royalties due others	367	318
Accrued interest	122	142
Deferred income taxes	30	39
Total Current Liabilities	2,390	1,890
LONG-TERM LIABILITIES:		
Long-term debt, net	10,872	7,376
Deferred income tax liability	3,900	3,317
Asset retirement obligation	218	193
Long-term derivative instruments	228	160
Revenues and royalties due others	38	30
Other liabilities	239	200
Total Long-Term Liabilities	15,495	11,276
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
4.125% cumulative convertible preferred stock, 3,062 and 3,065 shares issued and outstanding as of September 30, 2007 and December 31, 2006, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (series 2005), 4,600,000 shares issued and outstanding as of September 30, 2007 and December 31, 2006, entitled in liquidation to $460 million	460	460
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of September 30, 2007 and December 31, 2006, entitled in liquidation to $345 million	345	345
5.00% cumulative convertible preferred stock (series 2005B), 5,750,000 shares issued and outstanding as of September 30, 2007 and December 31, 2006, entitled in liquidation to $575 million	575	575
6.25% mandatory convertible preferred stock, 2,300,000 shares issued and outstanding as of September 30, 2007 and December 31, 2006, respectively, entitled in liquidation to $575 million	575	575
Common Stock, $.01 par value, 750,000,000 shares authorized, 474,222,339 and 458,600,789 shares issued at September 30, 2007 and December 31, 2006, respectively	5	5
Paid-in capital	5,976	5,873
Retained earnings	3,892	2,913
Accumulated other comprehensive income, net of tax of ($108) million and ($319) million, respectively	179	528
Less: treasury stock, at cost; 501,334 and 1,167,007 common shares as of September 30, 2007 and December 31, 2006, respectively	(6)	(26)
Total Stockholders Equity	12,004	11,251
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 29,889	$ 24,417

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	($ in millions except per share data)			
REVENUES:				
Oil and natural gas sales	$ 1,492	$ 1,493	$ 4,164	$ 4,190
Oil and natural gas marketing sales	501	398	1,446	1,170
Service operations revenue	34	38	101	98
Total Revenues	2,027	1,929	5,711	5,458
OPERATING COSTS:				
Production expenses	165	124	461	364
Production taxes	56	41	151	130
General and administrative expenses	62	37	168	99
Oil and natural gas marketing expenses	483	384	1,394	1,132
Service operations expense	23	19	67	49
Oil and natural gas depreciation, depletion and amortization	479	344	1,314	977
Depreciation and amortization of other assets	44	27	120	74
Employee retirement expense				55
Total Operating Costs	1,312	976	3,675	2,880
INCOME FROM OPERATIONS	715	953	2,036	2,578
OTHER INCOME (EXPENSE):				
Interest and other income	1	5	12	20
Interest expense	(116)	(74)	(279)	(220)
Gain on sale of investments			83	117
Total Other Income (Expense)	(115)	(69)	(184)	(83)
INCOME BEFORE INCOME TAXES	600	884	1,852	2,495
INCOME TAX EXPENSE:				
Current	9		19	
Deferred	219	335	685	963
Total Income Tax Expense	228	335	704	963
NET INCOME	372	549	1,148	1,532
PREFERRED STOCK DIVIDENDS	(26)	(26)	(77)	(62)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK				(11)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 346	$ 523	$ 1,071	$ 1,459
EARNINGS PER COMMON SHARE:				
Basic	$ 0.76	$ 1.25	$ 2.37	$ 3.75

Assuming dilution	$ 0.72	$ 1.13	$ 2.23	$ 3.40
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.0675	$ 0.06	$ 0.195	$ 0.17
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	454	418	452	389
Assuming dilution	517	483	516	451

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 1,148	$ 1,532
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,422	1,041
Deferred income taxes	671	963
Unrealized (gains) losses on derivatives	126	(453)
Amortization of loan costs and bond discount	19	15
Realized gains on financing derivatives	(76)	(96)
Stock-based compensation	59	78
Gain on sale of investments	(83)	(117)
Income from equity investments	(1)	(9)
Other		(4)
Change in assets and liabilities	104	33
Cash provided by operating activities	3,389	2,983
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties and leasehold, net of cash acquired	(2,331)	(3,546)
Exploration and development of oil and natural gas properties	(3,770)	(2,128)
Additions to drilling rig equipment	(112)	(341)
Additions to other property and equipment	(893)	(407)
Additions to investments	(7)	(538)
Acquisition of trucking company, net of cash acquired		(45)
Proceeds from sale of investments	124	159
Proceeds from sale of drilling rigs and equipment	322	188
Proceeds from sale of compressors	147	
Deposits for acquisitions		(12)
Sale of non-oil and natural gas assets	32	2
Cash used in investing activities	(6,488)	(6,668)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	5,949	7,058
Payments on long-term borrowings	(4,177)	(5,666)
Proceeds from issuance of senior notes, net of offering costs	1,607	969
Proceeds from issuance of common stock, net of offering costs		804
Proceeds from issuance of preferred stock, net of offering costs		558
Cash paid for common stock dividends	(85)	(62)
Cash paid for preferred stock dividends	(78)	(63)
Purchase of treasury shares		(86)
Derivative settlements	(65)	(68)
Net increase (decrease) in outstanding payments in excess of cash balance	(54)	43

Cash received from exercise of stock options	8	71
Excess tax benefit from stock-based compensation	13	86
Other financing costs	(20)	(18)
Cash provided by financing activities	3,098	3,626
Net increase (decrease) in cash and cash equivalents	(1)	(59)
Cash and cash equivalents, beginning of period	3	60
Cash and cash equivalents, end of period	$ 2	$ 1

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 274	$ 245
Income taxes, net of refunds received	$ 33	$
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

As of September 30, 2007 and 2006, dividends payable on our common and preferred stock were $56 million and $51 million, respectively.

For the nine months ended September 30, 2007 and 2006, oil and natural gas properties were adjusted by $130 million and $178 million, respectively, for net income tax liabilities related to acquisitions.

For the nine months ended September 30, 2007 and 2006, accrued exploration and development costs of $103 million and $73 million, respectively, were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to oil and natural gas properties of $15 million and $14 million for the nine months ended September 30, 2007 and 2006, respectively, for asset retirement obligations.

For the nine months ended September 30, 2007, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock, and for the nine months ended September 30, 2006, holders of our 4.125% preferred stock exchanged 2,750 shares for 172,594 shares of common stock in privately negotiated exchanges.

For the nine months ended September 30, 2006, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of common stock in privately negotiated exchanges.

For the nine months ended September 30, 2006, holders of our 6.0% cumulative convertible preferred stock converted 99,310 shares into 482,694 shares of common stock.

For the nine months ended September 30, 2006, holders of our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock exchanged 83,245 shares and 804,048 shares for 5,248,126 and 4,972,786 shares of common stock, respectively, in public exchange offers.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Nine Months Ended September 30, 2007	2006
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,958	$ 1,577
Issuance of 6.25% mandatory convertible preferred stock		575
Exchange of common stock for 3 and 85,995 shares of 4.125% preferred stock		(86)
Exchange of common stock for 0 and 987,321 shares of 5.00% preferred stock (Series 2003)		(99)
Exchange of common stock for 0 and 99,310 shares of 6.00% preferred stock		(5)
Balance, end of period	1,958	1,962
COMMON STOCK:		
Balance, beginning of period	5	4
Exchange of 180 and 12,016,423 shares of common stock for preferred stock		
Issuance of 0 and 28,750,000 shares of common stock		
Issuance of 0 and 1,375,989 shares of common stock for the purchase of Chaparral Energy, Inc. common stock		
Balance, end of period	5	4
PAID-IN CAPITAL:		
Balance, beginning of period	5,873	3,803
Issuance of 0 and 28,750,000 shares of common stock		835
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock		40
Exchange of 180 and 12,016,423 shares of common stock for preferred stock		189
Stock-based compensation	82	89
Adoption of SFAS 123(R)		(89)
Offering expenses		(49)
Exercise of stock options	8	71
Tax benefit from exercise of stock options and restricted stock	13	86
Release of 0 and 6,500,000 shares of treasury stock upon exercise of stock options		(75)
Balance, end of period	5,976	4,900
RETAINED EARNINGS:		
Balance, beginning of period	2,913	1,101
Net income	1,148	1,532
Dividends on common stock	(88)	(69)
Dividends on preferred stock	(77)	(69)
Adoption of FIN 48	(4)	
Balance, end of period	3,892	2,495
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	528	(195)
Hedging activity	(334)	1,144
Marketable securities activity	(15)	(87)

Balance, end of period	179	862
UNEARNED COMPENSATION:		
Balance, beginning of period		(89)
Adoption of SFAS 123(R)		89
Balance, end of period		
TREASURY STOCK - COMMON:		
Balance, beginning of period	(26)	(26)
Release of 665,673 and 221,759 shares for company benefit plans	20	7
Purchase of 0 and 2,707,471 shares of treasury stock		(86)
Release of 0 and 6,500,000 shares upon exercise of stock options		75
Balance, end of period	(6)	(30)
TOTAL STOCKHOLDERS EQUITY	$ 12,004	$ 10,193

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	($ in millions)			
Net income	$ 372	$ 549	$ 1,148	$ 1,532
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $68 million, $452 million, $3 million and $1.084 billion	110	751	6	1,800
Reclassification of gain on settled contracts, net of income taxes of ($65) million, ($105) million, ($243) million and ($269) million	(106)	(174)	(398)	(445)
Unrealized gain (loss) on ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $11 million, ($64) million, $35 million and ($126) million	17	(108)	57	(211)
Unrealized loss on marketable securities, net of income taxes of ($8) million, ($2) million, ($9) million and ($8) million	(13)	(4)	(15)	(14)
Reclassification of gain on sales of investments, net of income taxes of $0, $0, $0 and ($46) million				(73)
Comprehensive income	$ 380	$ 1,014	$ 798	$ 2,589

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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 2006 Annual Report on 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 nine months ended September 30, 2007 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and nine months ended September 30, 2007 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2006 (the Prior Quarter and the Prior Period , respectively).

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 oil and natural gas exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses, production expenses, oil and natural gas marketing expenses, service operations expense or employee retirement expense. We recorded the following stock-based compensation during the three and nine months ended September 30, 2007 and 2006, respectively ($ in millions):

For the three months ended September 30:	**2007**	**2006**
General and administrative expenses	$ 19	$ 8
Production expenses	7	3
Oil and natural gas marketing expenses	2	
Service operations expense	1	
Oil and natural gas properties	23	10
Total	$ 52	$ 21

For the nine months ended September 30:	**2007**	**2006**
General and administrative expenses	$ 41	$ 21
Production expenses	12	6
Oil and natural gas marketing expenses	3	
Service operations expense	2	
Employee retirement expense		51
Oil and natural gas properties	45	20
Total	$ 103	$ 98

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 unvested shares of restricted stock as of September 30, 2007, and changes during the Current Period, is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2007	7,074,761	$ 25.85
Granted	15,878,900	$ 34.22
Vested	(2,203,735)	$ 24.23
Forfeited	(927,988)	$ 33.22
Unvested shares as of September 30, 2007	19,821,938	$ 32.39

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $71 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Included in the 15.9 million shares of restricted stock granted during the Current Period are 9.8 million shares of restricted stock granted to our employees (except 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.

As of September 30, 2007, there was $609 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 3.36 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, $1 million, $4 million and $4 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options. Prior to 2005, 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, 2007	6,605,703	$ 7.43	5.36	$ 143
Exercised	(1,272,751)	$ 6.54		$ 33
Forfeited	(13,608)	$ 9.90		
Outstanding at September 30, 2007	5,319,344	$ 7.63	4.67	$ 147
Exercisable at September 30, 2007	5,284,854	$ 7.60	4.66	$ 146

(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 September 30, 2007, there was a nominal amount of total unrecognized compensation cost related to unvested stock options.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $2 million, $3 million, $9 million and $81 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Income Taxes

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006.

Chesapeake adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, Chesapeake recognized a $7 million liability for accrued interest associated with uncertain tax positions which was accounted for as a reduction in the January 1, 2007 balance of retained earnings, net of tax. At the date of adoption, we had approximately $142 million of unrecognized tax benefits related to alternative minimum tax (AMT) associated with uncertain tax positions. As of September 30, 2007, the amount of unrecognized tax benefits related to AMT associated with uncertain tax positions was $84 million. These AMT liabilities can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At September 30, 2007, we had a liability of $7 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2004. The Internal Revenue Service (IRS) completed an examination of Chesapeake s U.S. income tax returns for 2003 and 2004 in September 2007. This examination resulted in additional AMT liabilities of $9 million. These AMT liabilities can be utilized as credits against future regular tax liabilities. The adjustments in the examination did not result in a material change to our financial position, results of operations or cash flows.

Oil and Natural Gas Properties Impact of Cash Flow Hedges on Ceiling Test

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission (SEC) on a quarterly and annual basis. This review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (including the impact of cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

In calculating future net revenues, prices and costs used are those as of the end of the appropriate quarterly period except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Our qualifying cash flow hedges as of September 30, 2007, which consisted of swaps and collars, covered 121 bcfe, 351 bcfe, 102 bcfe and 25 bcfe in 2007, 2008, 2009 and 2010, respectively. Our oil and natural gas hedging activities are discussed in Note 2 of these condensed consolidated financial statements and in Item 3. *Quantitative and Qualitative Disclosures About Market Risk* of Part I of this Form 10-Q. Based on spot prices for oil and natural gas as of September 30, 2007, these cash flow hedges increased the full cost ceiling by $1.182 billion, thereby reducing any potential ceiling test write-down by the same amount. Had the effects of our cash flow hedges not been considered in calculating the ceiling limitation, the impairment as of September 30, 2007 would have been approximately $916 million.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2006.

2. Financial Instruments and Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2007, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, knockout swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which 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 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 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 oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

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

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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) are included in oil and natural gas 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 oil and natural gas 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 recognized currently in oil and natural gas sales as unrealized gains (losses). The components of oil and natural gas sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	($ in millions)			
Oil and natural gas sales	$ 1,161	$ 953	$ 3,361	$ 2,930
Realized gains on oil and natural gas derivatives	286	301	916	807
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	73	67	(21)	116
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(28)	172	(92)	337
Total oil and natural gas sales	$ 1,492	$ 1,493	$ 4,164	$ 4,190

The estimated fair values of our oil and natural gas derivative instruments as of September 30, 2007 and December 31, 2006 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30,	December 31,
	2007	2006
	($ in millions)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (38)	$ 1
Natural gas basis protection swaps	180	187
Fixed-price natural gas knockout swaps	71	122
Fixed-price natural gas counter-swaps		(5)
Natural gas call options[(a)]	(143)	(5)
Fixed-price natural gas collars		(7)
Fixed-price oil swaps	(40)	28
Fixed-price oil cap-swaps		24
Fixed-price oil knockout swaps	(17)	
Oil call options[(b)]	(36)	
Estimated fair value	$ (23)	$ 345

(a) After adjusting for $183 million and $15 million of unrealized premiums, the cumulative unrealized gain (loss) related to these call options as of September 30, 2007 and December 31, 2006 was $40 million and $10 million, respectively.

(b)

After adjusting for $29 million of unrealized premiums, the cumulative unrealized loss related to these call options as of September 30, 2007 was ($7) million.

In 2006 and 2007, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result has approximately $435 million of deferred hedging gains as of September 30, 2007. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in oil and natural gas sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

Based upon the market prices at September 30, 2007, we expect to transfer approximately $195 million (net of income taxes) of the gain 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 September 30, 2007 are expected to mature by December 31, 2012.

We have six secured hedging facilities, each of which permits us to enter into cash-settled oil and natural gas commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a per annum exposure fee, which is assessed quarterly based on the

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility, per annum exposure fees, scheduled maturity dates and the fair value of outstanding transactions are shown below.

	Secured Hedging Facilities [(a)]					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Maximum permitted value of transactions under facility	$ 750	$ 500	$ 500	$ 250	$ 500	$ 500
Per annum exposure fee	1%	1%	1%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2011	2012	2012	2012
Fair value of outstanding transactions, as of September 30, 2007	$ 22	$ (158)	$ (33)	$ (14)	$ (1)	$ (1)

(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.

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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 aggregate fair value of the remaining CNR derivatives as of September 30, 2007 was a liability of $204 million.

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 derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to 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 $1 million, ($2) million, a nominal amount and $1 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Pursuant to SFAS 133, certain interest rate derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were ($19) million, $3 million, ($13) million and $1 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

As of September 30, 2007, 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:							
July 2005 November 2020	$ 1,750	6.929%	6 month LIBOR plus 180 basis points		Yes	$	$ (17)
September 2004 July 2013	$ 325	7.942%	6 month LIBOR plus 297 basis points		No		(1)
Floating to Fixed Swaps:							
August 2007 August 2009	$ 500	5.034%	3 month LIBOR		No		(4)
Call Options:							
June 2007 February 2008	$ 750	7.000%			No	5	(15)
Collars:							
August 2007 August 2010	$ 1,325			5.37% - 4.32%	No		(7)
						$ 5	$ (44)

In the Current Period, we sold call options on five of our interest rate swaps and received $9 million in premiums. Two of the options expired unexercised in the Current Period.

In the Current Period, we closed eight interest rate swaps for gains totaling $9 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 will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield 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 ($853 million at September 30, 2007) using an exchange rate of $1.4219 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $17 million at September 30, 2007. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

Fair Value of Financial Instruments

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

The carrying values of financial instruments comprising current assets and current liabilities approximate the fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at September 30, 2007 and December 31, 2006 were $8.920 billion and $7.215 billion, respectively, compared to approximate fair values of $9.068 billion and $7.336 billion, respectively. The carrying amount for our convertible preferred stock as of September 30, 2007 and December 31, 2006 was $1.958 billion, compared to approximate fair values of $2.040 billion and $1.949 billion, respectively.

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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 oil and natural gas price and interest rate volatility. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. 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.

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 in the Circuit Court of Roane County, West Virginia filed in 2003 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. Most of the damages awarded by the jury relate to issues not yet addressed by the West Virginia Supreme Court of Appeals, although in June 2006 that Court ruled against the defendants on two certified questions regarding the deductibility of post-production expenses. 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, including defendants motion for judgment as a matter of law, or in the alternative, for a new trial. The defendants motion for stay pending appeal is set for hearing on November 16, 2007.

Chesapeake and NiSource maintain CNR acted in good faith and paid royalties in accordance with lease terms and West Virginia law, and will appeal the final judgment. Chesapeake has established an accrual for amounts it believes will not be indemnified. Should a final nonappealable judgment be entered, Chesapeake believes its share of damages 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 term of the agreement with the chief executive officer expires December 31, 2012 unless extended. The term is automatically extended for one additional year on each December 31 unless the company provides at least 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 other than participation in any retirement or deferred compensation plan 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. Any stock-based awards and deferred compensation held by the chief executive officer will immediately become 100% vested upon termination of employment without cause, incapacity, death or retirement at or after age 55.

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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 and, in the event of a change of control, a payment in the amount of two times the executive officer s annual base compensation. 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 oil and natural gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in 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 September 30, 2007.

Rig Leases

In a series of transactions in 2006 and 2007, our drilling subsidiaries have sold 70 drilling rigs and related equipment for $565 million and entered into a master lease agreement under which they agreed to lease the rigs from the buyer for initial terms of seven to ten years for rental payments of approximately $80 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. Commitments related to these lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2007, the minimum aggregate future rig lease payments were approximately $591 million.

Compressor Leases

In September 2007, our wholly owned subsidiary, MidCon Compression, L.L.C., sold a significant portion of its existing compressor fleet, consisting of 1,085 compressors, for $161 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 $18 million annually. MidCon s 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 oil and natural gas marketing expenses over the lease term. Under the leases, we can exercise an early purchase option after 72 to 109 months 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. Over the next 18 months, approximately 400 new compressors are on order for $167 million and will be sold and leased back as the compressors are delivered. Commitments related to these lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2007, the minimum aggregate future compressor lease payments were approximately $185 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 September 30, 2007, the aggregate amount of such required demand payments was approximately $493 million (excluding demand charges for pipeline projects that are currently seeking regulatory approval).

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Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to use approximately 33 rigs with terms of one to three years. As of September 30, 2007, the aggregate drilling rig commitment was approximately $272 million.

As of September 30, 2007, Chesapeake s service operations subsidiaries have contracted to acquire 3 rigs to be constructed during 2007. The total remaining cost of the rigs is estimated to be approximately $21 million.

Other Commitments

Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to $32 million each through December 31, 2009. At September 30, 2007, Mountain Drilling owes Chesapeake $28 million under this agreement.

Chesapeake has an agreement to lend Ventura Refining and Transmission LLC, of which Chesapeake is a 25% equity owner, up to $26 million through January 31, 2017. At September 30, 2007, there was $19 million outstanding under this agreement. Additionally, we have agreed to guarantee various commitments for Ventura, up to $75 million, to support their operating activities. At September 30, 2007, we had guaranteed $61 million of commitments.

4. Net Income Per Share

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

For the Prior Quarter, outstanding options to purchase 0.1 million shares of common stock at a weighted average exercise price of $30.63 were not included in the calculation of diluted earnings per share. The effect was antidilutive because the exercise price was greater than the average market price of the common stock during the period.

Reconciliations for the three and nine months ended September 30, 2007 and 2006 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Three Months Ended September 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 346	454	$ 0.76
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% mandatory convertible preferred stock		17	

Employee stock options		3	
Restricted stock		2	
Preferred stock dividends	26		
Diluted EPS Income available to common shareholders and assumed conversions	$ 372	517	$ 0.72

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	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
For the Three Months Ended September 30, 2006:			
Basic EPS:			
Income available to common shareholders	$ 523	418	$ 1.25
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		19	
Employee stock options		4	
Restricted stock		1	
Preferred stock dividends	26		
Diluted EPS Income available to common shareholders and assumed conversions	$ 549	483	$ 1.13
For the Nine Months Ended September 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 1,071	452	$ 2.37
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% mandatory convertible preferred stock		17	
Employee stock options		4	
Restricted stock		2	
Preferred stock dividends	77		
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,148	516	$ 2.23
For the Nine Months Ended September 30, 2006:			
Basic EPS:			
Income available to common shareholders	$ 1,459	389	$ 3.75
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		6	

Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion,			
4.125% convertible preferred stock		3	
5.00% convertible preferred stock (Series 2003)		3	
Employee stock options		7	
Restricted stock		2	
Loss on redemption of preferred stock	11		
Preferred stock dividends	62		
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,532	451	$ 3.40

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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5. Stockholders Equity

The following is a summary of the changes in our common shares outstanding for the nine months ended September 30, 2007 and 2006:

	2007	2006
	(in thousands)	
Shares outstanding at January 1	458,601	375,511
Stock option exercises	1,254	6,676
Restricted stock issuances	14,367	13,530
Preferred stock conversions/exchanges		12,016
Common stock issuances		28,750
Common stock issued for the purchase of Chaparral Energy, Inc. common stock		1,376
Shares outstanding at September 30	474,222	437,859

The following is a summary of the changes in our preferred shares outstanding for the nine months ended September 30, 2007 and 2006:

	6.00%	5.00% (2003)	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)				
Shares outstanding at January 1, 2007			3	4,600	3,450	5,750	2,300
Conversion/exchange of preferred for common stock							
Shares outstanding at September 30, 2007			3	4,600	3,450	5,750	2,300
Shares outstanding at January 1, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,300
Conversion/exchange of preferred for common stock	(99)	(987)	(86)				
Shares outstanding at September 30, 2006		39	3	4,600	3,450	5,750	2,300

In the Current 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.

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

In the Prior Period, shares of our preferred stock were exchanged for or converted into common stock as follows:

183,273 shares of 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for or converted into 1,140,223 shares of common stock in privately negotiated exchange transactions or pursuant to conversion rights;

804,048 shares of such 5.0% (Series 2003) cumulative convertible preferred stock were exchanged for 4,972,786 shares of common stock pursuant to a tender offer;

2,750 shares of 4.125% cumulative convertible preferred stock were exchanged for 172,594 shares of common stock in privately negotiated exchange transactions;

83,245 shares of such 4.125% cumulative convertible preferred stock were exchanged for 5,248,126 shares of common stock pursuant to a tender offer; and

the remaining 99,310 shares of 6.0% cumulative convertible preferred stock were converted into 482,694 shares of common stock pursuant to conversion rights.

In connection with the exchanges noted above, we recorded a loss of $11 million in the Prior Period. In general, the losses are equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

6. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of September 30, 2007 and December 31, 2006:

	September 30, 2007	December 31, 2006
	($ 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
7.75% Senior Notes due 2015	300	300
6.375% Senior Notes due 2015	600	600
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.5% Senior Notes due 2017	1,100	1,100
6.25% Euro-denominated Senior Notes due 2017[a]	853	792
6.25% Senior Notes due 2018	600	600
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035[b]	690	690
2.5% Contingent Convertible Senior Notes due 2037[b]	1,650	
Revolving bank credit facility	1,950	178
Discount on senior notes	(107)	(101)
Premium (discount) for interest rate derivatives[c]	2	(17)
Total notes payable and long-term debt	$ 10,872	$ 7,376

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4219 to 1.00 and $1.3197 to 1.00 as of September 30, 2007 and December 31, 2006, respectively. See Note 2 for information on our related cross currency swap.

(b) The holders of our Contingent Convertible Senior Notes may require us to repurchase all or a portion of their notes 5, 10, 15 or 20 years prior to the maturity date, or upon a fundamental change, at 100% of the principal amount of the notes, payable in cash. 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. In general, upon conversion of a 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. In addition, we will pay contingent interest on the convertible senior notes, beginning with the six-month interest period ending May 14, 2016 with respect to the 2.75% Contingent Convertible Senior Notes due 2035 and November 14, 2017 with respect to the 2.5% Contingent Convertible Senior Notes due 2037, 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.

(c) 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 2.75% Contingent Convertible Senior Notes due 2035 and the 2.5% Contingent Convertible Senior Notes due 2037, 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 restricted 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.

On November 2, 2007, we amended and restated our syndicated revolving bank credit facility to increase the borrowing base to $3.5 billion (with commitments of $3.0 billion) and extended the maturity to November 2012. As of September 30, 2007, we had $1.950 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

by certain producing oil and natural gas properties and bear interest 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), at our option, plus a margin that varies from 0.75% to 1.50% 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 govern 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 0.48 to 1 and our indebtedness to EBITDA ratio was 2.28 to 1 at September 30, 2007. 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 segment and oil and natural gas 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 oil and natural gas. The marketing segment is responsible for gathering, processing, compressing, transporting and selling oil and natural gas 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 before income taxes. Revenues from the marketing segment s sale of oil and natural gas related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $843 million, $631 million, $2.441 billion and $1.919 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 ($ in millions)	Intercompany Eliminations	Consolidated Total
For the Three Months Ended September 30, 2007:					
Revenues	$ 1,492	$ 1,344	$ 133	$ (942)	$ 2,027
Intersegment revenues		(843)	(99)	942	
Total revenues	$ 1,492	$ 501	$ 34	$	$ 2,027
Income before income taxes	$ 586	$ 11	$ 38	$ (35)	$ 600

For the Three Months Ended September 30, 2006:					
Revenues	$ 1,493	$ 1,029	$ 98	$ (691)	$ 1,929
Intersegment revenues		(631)	(60)	691	
Total revenues	$ 1,493	$ 398	$ 38	$	$ 1,929
Income before income taxes	$ 867	$ 9	$ 34	$ (26)	$ 884

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Exploration and Production	Marketing	Other Operations (in millions)	Intercompany Eliminations	Consolidated Total
For the Nine Months Ended September 30, 2007:					
Revenues	$ 4,164	$ 3,887	$ 357	$ (2,697)	$ 5,711
Intersegment revenues		(2,441)	(256)	2,697	
Total revenues	$ 4,164	$ 1,446	$ 101	$	$ 5,711
Income before income taxes	$ 1,813	$ 29	$ 104	$ (94)	$ 1,852
For the Nine Months Ended September 30, 2006:					
Revenues	$ 4,190	$ 3,089	$ 219	$ (2,040)	$ 5,458
Intersegment revenues		(1,919)	(121)	2,040	
Total revenues	$ 4,190	$ 1,170	$ 98	$	$ 5,458
Income before income taxes	$ 2,448	$ 29	$ 68	$ (50)	$ 2,495
As of September 30, 2007:					
Total assets	$ 28,723	$ 1,182	$ 619	$ (635)	$ 29,889
As of December 31, 2006:					
Total assets	$ 23,333	$ 864	$ 786	$ (566)	$ 24,417

8. Acquisitions and Investments

Oil and Natural Gas Properties

Through multiple acquisitions completed in the Current Period, we invested $623 million in proved properties and $1.885 billion in leasehold and unproved property acquisitions, including capitalized interest. Additionally, we recorded approximately $130 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

Investments

In the Current 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 pre-tax gain of $83 million.

9. 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 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments we acquire or issue after December 31, 2006. Adoption of SFAS 155 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. 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 February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. 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. 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.

The FASB has announced that it plans to issue proposed staff guidance on accounting for convertible debt instruments that may be settled in cash upon conversion, including partial cash settlements. This accounting could

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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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 would 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 two debt series that would be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037. If the FASB adopts the guidance, it is expected to be effective for fiscal years starting after December 15, 2007. Companies would have to apply the guidance retrospectively to both existing and new instruments that fall within the scope of the guidance.

10. Subsequent Events

On October 23, 2007, we commenced offers to exchange common stock for any and all of the 4,600,000 outstanding shares of our 5% Cumulative Convertible Preferred Stock (Series 2005) and 2,300,000 outstanding shares of our 6.25% Mandatory Convertible Preferred Stock. The offers are scheduled to expire on November 20, 2007.

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PART I. FINANCIAL INFORMATION

ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***
Overview

The following table sets forth certain information regarding the production volumes, oil and natural gas sales, average sales prices received, other operating income and expenses for the three and nine months ended September 30, 2007 (the Current Quarter and the Current Period) and the three and nine months ended September 30, 2006 (the Prior Quarter and the Prior Period):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Net Production:				
Oil (mbbls)	2,680	2,178	7,147	6,437
Natural gas (mmcf)	170,325	133,822	467,197	387,696
Natural gas equivalent (mmcfe)	186,405	146,890	510,079	426,318
Oil and Natural Gas Sales ($ in millions):				
Oil sales	$ 190	$ 142	$ 443	$ 404
Oil derivatives realized gains (losses)	(4)	(10)	26	(26)
Oil derivatives unrealized gains (losses)	(28)	29	(55)	25
Total oil sales	158	161	414	403
Natural gas sales	971	811	2,918	2,526
Natural gas derivatives realized gains (losses)	290	311	890	833
Natural gas derivatives unrealized gains (losses)	73	210	(58)	428
Total natural gas sales	1,334	1,332	3,750	3,787
Total oil and natural gas sales	$ 1,492	$ 1,493	$ 4,164	$ 4,190
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 70.76	$ 65.05	$ 61.91	$ 62.85
Natural gas ($ per mcf)	$ 5.71	$ 6.06	$ 6.25	$ 6.52
Natural gas equivalent ($ per mcfe)	$ 6.23	$ 6.49	$ 6.59	$ 6.87
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 69.25	$ 60.62	$ 65.55	$ 58.86
Natural gas ($ per mcf)	$ 7.41	$ 8.39	$ 8.15	$ 8.66
Natural gas equivalent ($ per mcfe)	$ 7.76	$ 8.54	$ 8.39	$ 8.77
Other Operating Income[(a)] ($ in millions):				
Oil and natural gas marketing	$ 18	$ 14	$ 52	$ 38
Service operations	$ 11	$ 19	$ 34	$ 49
Other Operating Income ($ per mcfe):				
Oil and natural gas marketing	$ 0.10	$ 0.09	$ 0.10	$ 0.09
Service operations	$ 0.06	$ 0.13	$ 0.07	$ 0.11
Expenses ($ per mcfe):				
Production expenses	$ 0.89	$ 0.84	$ 0.90	$ 0.85
Production taxes	$ 0.30	$ 0.28	$ 0.30	$ 0.30
General and administrative expenses	$ 0.33	$ 0.25	$ 0.33	$ 0.23
Oil and natural gas depreciation, depletion and amortization	$ 2.57	$ 2.34	$ 2.58	$ 2.29
Depreciation and amortization of other assets	$ 0.24	$ 0.18	$ 0.24	$ 0.17
Interest expense[(b)]	$ 0.52	$ 0.52	$ 0.52	$ 0.52

Interest Expense ($ in millions):				
Interest expense	$ 98	$ 75	$ 266	$ 222
Interest rate derivatives realized (gains) losses	(1)	2		(1)
Interest rate derivatives unrealized (gains) losses	19	(3)	13	(1)
Total interest expense	$ 116	$ 74	$ 279	$ 220
Net Wells Drilled	529	401	1,480	985
Net Producing Wells as of the End of the Period	20,932	18,511	20,932	18,511

(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.

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We believe we are the third largest producer of natural gas in the United States (first among independents). We own interests in approximately 37,500 producing oil and natural gas wells that are currently producing approximately 2.2 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 in various conventional plays in the *Mid-Continent region* of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At September 30, 2007, 47% of our estimated proved oil and natural gas reserves were located in the Mid-Continent region. During the past five years, we have also built significant positions in various conventional and unconventional plays in the *Fort Worth Basin* in north-central Texas; the *Appalachian Basin*, principally in West Virginia, eastern Kentucky, eastern Ohio, Pennsylvania and southern New York; the *Permian and Delaware Basins* of West Texas and eastern New Mexico; the *Ark-La-Tex* area of East Texas and northern Louisiana; and the *South Texas and Texas Gulf Coast regions*. We have established a top-three position in nearly every major unconventional play onshore in the U.S. east of the Rockies, including the Fort Worth Barnett Shale, the Arkansas Fayetteville Shale, the Appalachian Basin Devonian and Marcellus Shales, the southeast Oklahoma Woodford Shale, the Delaware Basin Barnett and Woodford Shales and the Alabama Conasauga, Floyd and Chattanooga Shales.

Oil and natural gas production for the Current Quarter was 186.4 bcfe, an increase of 39.5 bcfe, or 27% over the 146.9 bcfe produced in the Prior Quarter. This growth was achieved despite the curtailment of approximately 3.0 bcfe of the company s net production during September 2007. We have increased our production for 25 consecutive quarters. During these 25 quarters, Chesapeake s U.S. production has increased 417% for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 30%.

During the Current Period, Chesapeake continued the industry s most active drilling program and drilled 1,523 gross (1,307 net) operated wells and participated in another 1,262 gross (173 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during the Current Period, Chesapeake invested $3.1 billion in operated wells (using an average of 138 operated rigs) and $547 million in non-operated wells (using an average of 104 non-operated rigs). Total costs incurred in oil and natural gas acquisition, exploration and development activities during the Current Period, including seismic, unproved properties, leasehold, capitalized interest and internal costs, non-cash tax basis step-up and asset retirement obligations, were $6.5 billion.

Chesapeake began 2007 with estimated proved reserves of 8.956 tcfe and based on internal estimates ended the Current Quarter with 10.562 tcfe, an increase of 1.606 tcfe, or 18%. During the Current Period, we replaced our 510 bcfe of production with an estimated 2.116 tcfe of new proved reserves, for a reserve replacement rate of 415%. Reserve replacement through the drillbit was 1.761 tcfe, or 345% of production (including 859 bcfe of positive performance revisions and 79 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and September 30, 2007) and 83% of the total increase. Reserve replacement through the acquisition of proved reserves completed during the Current Period was 355 bcfe, or 70% of production and 17% of the total increase. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2007 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.

In order to execute our extensive exploration and development program, we have continued to significantly strengthen our technical capabilities by increasing our land, geoscience and engineering staff to more than 1,300 employees. Today, the company has approximately 6,000 employees, of whom approximately 60% work in the company s E&P operations and approximately 40% work in the company s oilfield service operations.

Since 2000, Chesapeake has invested $8.8 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventory of onshore leasehold (12.5 million net acres) and 3-D seismic (18.5 million acres) in the U.S. On this leasehold, the company has an estimated 28,000 net drilling locations, representing an approximate 10-year inventory of drilling projects.

As of September 30, 2007, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 48% compared to 40% as of December 31, 2006. The average maturity of our long-term debt is almost nine years and our average interest rate is approximately 5.8%.

Liquidity and Capital Resources

New Financing Plan

In early September 2007, we announced an enhanced financial plan designed to monetize unrecognized balance sheet value and to fully fund our planned capital expenditures through 2009 without accessing public capital markets. Since then, we have successfully implemented multiple aspects of the plan and anticipate further progress over the next two quarters. We believe our planned transactions described below will allow us to monetize over $4 billion of assets by the end of 2009.

Sale/Leasebacks. During the Current Quarter, we completed our third sale/leaseback transaction on 37 drilling rigs for net proceeds of approximately $235 million. We have now completed sale/leaseback transactions on a total of 70 rigs and anticipate completing similar transactions on our remaining 11 rigs during the fourth quarter of 2007, thereby completing the sale/leaseback of our entire fleet of 81 drilling rigs. Also during the Current Quarter, we completed a sale/leaseback facility for our natural gas compression assets. We received approximately $160 million for the sale/leaseback of our existing natural gas compression assets and we will finance up to $185 million of future natural gas compression assets under the same facility.

Producing Property Sales. We are currently in the process of monetizing certain Chesapeake-operated producing assets in Kentucky and West Virginia. The company intends to retain drilling rights on the properties below currently producing intervals and outside of existing producing wellbores. Chesapeake has received multiple attractive offers for the Appalachian assets with a variety of transaction structures. We anticipate completing a monetization transaction by year-end 2007 for proceeds in excess of $1.0 billion. In addition, we also plan to pursue four more monetizations of similarly mature properties in 2008 and 2009 for further proceeds of approximately $2.0 billion.

The company is also currently in the process of selling non-core E&P assets in the Rocky Mountains and in the southeastern Oklahoma Woodford Shale play for expected proceeds in excess of $300 million. These sales are anticipated to close by the first quarter of 2008. In total, Chesapeake is anticipating receiving monetization and sale proceeds of approximately $3.3 billion by year-end 2009.

Midstream MLP. We are currently in the process of forming a private MLP to own a non-operating interest in our midstream natural gas assets outside of Appalachia, which consist primarily of gas gathering systems and processing assets. These assets, which are expected to grow substantially in future years, currently generate annualized cash flow from operating activities in excess of $100 million. We believe our MLP transaction will be valued at more than $1 billion and is anticipated to close in the first quarter of 2008.

Sources and Uses of Funds

Cash flow from operations is our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for acquisitions outside our budgeted leasehold and property acquisitions). Cash provided by operating activities was $3.389 billion in the Current Period compared to $2.983 billion in the Prior Period. The $406 million increase in the Current Period was primarily due to higher oil and natural gas 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 ($1.422 billion and $1.041 billion during the Current Period and the Prior Period, respectively), deferred income taxes ($671 million and $963 million during the Current Period and the Prior Period, respectively) and unrealized gains and (losses) on derivatives (($126) million and $453 million during the Current Period and the Prior Period, respectively). Net income decreased to $1.148 billion in the Current Period from $1.532 billion in the Prior Period and is discussed below under *Results of Operations*.

Changes in market prices for oil and natural gas directly impact the level of our cash flow from operations. While a decline in oil or natural gas prices would affect the amount of cash flow that would be generated from operations, we currently have oil hedges in place covering 99% of our expected oil production in the fourth quarter of 2007 and in 2008, 98% of our expected natural gas production in the fourth quarter of 2007 and 85% of our expected natural gas production in 2008, thereby providing certainty for a substantial portion of our future cash flow. Our oil and natural gas hedges as of September 30, 2007 are detailed in Item 3 of Part I of this report. 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 oil and natural gas hedges by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. Depending on changes in oil and natural gas futures markets and management s view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions.

On November 2, 2007, we established a new five-year $3.0 billion committed senior secured revolving credit facility that replaced the company s previous $2.5 billion facility. The new facility reflects the increased scale and scope of the company s operations and will help accommodate timing differences between cash flow from operations, asset monetizations and planned capital expenditures. At November 7, 2007, there was $288 million 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 $5.949 billion and repaid $4.177 billion in the Current Period, and we borrowed $7.058 billion and repaid $5.666 billion in the Prior Period under the credit facility.

We believe our cash flow from operations, in combination with the proceeds expected from our planned producing property monetizations and other asset sales and the $500 million increase in our bank credit facility borrowing ability will provide us sufficient liquidity to execute our business strategy without accessing the public capital markets for the foreseeable future. We intend to use any cash in excess of our operating and capital expenditure needs to pay down indebtedness under our revolving bank credit facility.

In the Current Period, we completed two public offerings of our 2.5% Contingent Convertible Senior Notes due 2037. In the first offering, in May 2007, we issued $1.150 billion of notes and in the second offering, in August 2007, we issued $500 million of notes. Net proceeds of approximately $1.124 billion and $483 million, respectively, were used to repay outstanding borrowings under our revolving bank credit facility. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30,			
	2007		2006	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$	$	$ 575	$ 558

Common stock			835	804
Contingent convertible unsecured senior notes	1,650	1,607		
Unsecured senior notes guaranteed by subsidiaries			1,000	969
Total	$ 1,650	$ 1,607	$ 2,410	$ 2,331

Our primary use of funds is our capital expenditures for exploration, development and acquisition of oil and natural gas properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our oil and natural gas investing activities for the Current Period and the Prior Period. Our drilling, land and seismic capital expenditures are currently budgeted at $5.7 billion to $6.2 billion in 2007 and $5.4 billion to $5.9

billion in 2008. We believe this level of exploration and development will enable us to increase our proved oil and natural gas reserves by more than 20% in 2007 and 13% in 2008 and increase our total production by 21% to 23% in 2007 and 18% to 22% in 2008 (inclusive of acquisitions completed or scheduled to close in 2007 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2007).

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 $85 million and $62 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.06 to $0.0675 per share beginning with the dividend paid in July 2007. We paid dividends on our preferred stock of $78 million and $63 million in the Current Period and the Prior Period, respectively. We received $8 million and $71 million from the exercise of employee and director stock options in the Current Period and the Prior Period, respectively. The Prior Period amount included $38 million paid by Tom L. Ward, our former President and Chief Operating Officer, to exercise all of his stock options following his resignation in February 2006.

In the Current Period and Prior Period, we paid $65 million and $68 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 $13 million and $86 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists decreased by $54 million in the Current Period and increased by $43 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.

Our accounts receivable are primarily from purchasers of oil and natural gas ($604 million at September 30, 2007) and exploration and production companies which own interests in properties we operate ($137 million at September 30, 2007). 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 for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Investing Activities

Cash used in investing activities decreased to $6.488 billion during the Current Period, compared to $6.668 billion during the Prior Period. Over the past year, we have accelerated our drilling program and shifted our acquisition strategy from significant stock and asset acquisitions to targeted leasehold and property acquisitions needed for planned oil and natural gas development. Our investing activities during the Current Period and the Prior Period reflect our increasing focus on converting our resource inventory into production as well as elements of our new financing plan. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Nine Months Ended September 30,	
	2007	**2006**
Oil and Natural Gas Investing Activities:		
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 446	$ 961
Acquisition of leasehold and unproved properties	1,703	2,470
Exploration and development of oil and natural gas properties	3,525	2,026
Geological and geophysical costs	245	102
Interest on leasehold and unproved properties	182	115
Total oil and natural gas investing activities	6,101	5,674

Other Investing Activities:		
Additions to drilling rig equipment	112	341
Additions to other property and equipment	893	407
Proceeds from sale of drilling rigs and equipment	(322)	(188)
Proceeds from sale of compressors	(147)	
Additions to investments	7	538
Proceeds from sale of investments	(124)	(159)
Acquisition of trucking company, net of cash acquired		45
Deposits for acquisitions		12
Sale of non-oil and natural gas assets	(32)	(2)
Total other investing activities	387	994
Total cash used in investing activities	$ 6,488	$ 6,668

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Bank Credit and Hedging Facilities

On November 2, 2007, we amended and restated our syndicated revolving bank credit facility to increase the borrowing base to $3.5 billion (with commitments of $3.0 billion) and extended the maturity to November 2012. As of September 30, 2007, we had $1.950 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 oil and natural gas properties and bear interest 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), at our option, 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, our indebtedness to total capitalization ratio was 0.48 to 1 and our indebtedness to EBITDA ratio was 2.28 to 1 at September 30, 2007. 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 oil and natural gas commodity transactions, valued by the counterparty, for up to a maximum value. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. 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 oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time. The maximum permitted value of transactions under each facility and the fair value of outstanding transactions are shown below.

	Secured Hedging Facilities [(a)] ($ in millions)					
	#1	#2	#3	#4	#5	#6
Maximum permitted value of transactions under facility	$ 750	$ 500	$ 500	$ 250	$ 500	$ 500
Per annum exposure fee	1%	1%	1%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2010	2011	2012	2012	2012
Fair value of outstanding transactions, as of September 30, 2007	$ 22	$ (158)	$ (33)	$ (14)	$ (1)	$ (1)

(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.

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Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of September 30, 2007, senior notes represented approximately $8.922 billion of our long-term debt and consisted of the following ($ 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
7.75% Senior Notes due 2015	300
6.375% Senior Notes due 2015	600
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.5% Senior Notes due 2017	1,100
6.25% Euro-denominated Senior Notes due 2017 [a]	853
6.25% Senior Notes due 2018	600
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035	690
2.5% Contingent Convertible Senior Notes due 2037	1,650
Discount on senior notes	(107)
Premium for interest rate derivatives	2
	$ 8,922

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.4219 to 1.00 as of September 30, 2007. See Note 2 of our accompanying condensed consolidated financial statements for information on our related cross currency swap.

No scheduled principal payments are required under our senior notes until 2013, when $864 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase, in cash, all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes. The holders of the 2.5% Contingent Convertible Senior Notes due 2037 may require us to repurchase, in cash, all or a portion of these notes on May 15, 2017, 2022, 2027 and 2032 at 100% of the principal amount of the notes.

As of September 30, 2007 and currently, debt ratings for the senior notes are Ba2 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (positive outlook) and BB by Fitch Ratings (negative outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly-owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. 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 restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of September 30, 2007, we estimate that secured commercial bank indebtedness of approximately $3.9 billion could have been incurred under the most restrictive indenture covenant.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at September 30, 2007. 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 1 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 135 of our field employees in West Virginia and Kentucky. We have 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 . 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. On November 2, 2007, the Union Negotiating Team informed us that they will allow the Union membership to vote on our last offer. No date for the vote has been scheduled and we can provide no assurance that the vote, if taken, will pass.

Results of Operations - Three Months Ended September 30, 2007 vs. September 30, 2006

General. For the Current Quarter, Chesapeake had net income of $372 million, or $0.72 per diluted common share, on total revenues of $2.027 billion. This compares to net income of $549 million, or $1.13 per diluted common share, on total revenues of $1.929 billion during the Prior Quarter.

Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.492 billion compared to $1.493 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 186.4 bcfe at a weighted average price of $7.76 per mcfe, compared to 146.9 bcfe produced in the Prior Quarter at a weighted average price of $8.54 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $45 million and $239 million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $145 million and increased production resulted in a $338 million increase, for a total increase in revenues of $193 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Quarter to the Current Quarter is primarily generated from the drillbit.

For the Current Quarter, we realized an average price per barrel of oil of $69.25, compared to $60.62 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $7.41 and $8.39 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $286 million, or $1.53 per mcfe, in the Current Quarter and $301 million, or $2.05 per mcfe, in the Prior Quarter.

Changes in oil and natural gas prices have a significant impact on our oil and natural gas 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 $17 million and $16 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 $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 September 30,			
	2007		2006	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	97,775	52%	80,946	55%
Fort Worth Barnett Shale	23,960	13	11,557	8
South Texas and Texas Gulf Coast	19,582	10	19,421	13
Permian and Delaware Basins	18,322	10	11,687	8
Ark-La-Tex	14,492	8	11,529	8
Appalachian Basin	12,274	7	11,750	8
Total production	186,405	100%	146,890	100%

Natural gas production represented approximately 91% of our total production volume on a natural gas equivalent basis in both the Current Quarter and the Prior Quarter.

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Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing sales and operating expenses are from third parties who are owners in Chesapeake-operated wells. Chesapeake recognized $501 million in oil and natural gas marketing sales in the Current Quarter, with corresponding oil and natural gas marketing expenses of $483 million, for a net margin before depreciation of $18 million. This compares to sales of $398 million, expenses of $384 million and a net margin before depreciation of $14 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and natural gas marketing sales volumes related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations revenue and expenses consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired and built in 2006 and 2007. Chesapeake recognized $34 million in service operations revenue in the Current Quarter with corresponding service operations expense of $23 million, for a net margin before depreciation of $11 million. This compares to revenue of $38 million, expenses of $19 million and a net margin before depreciation of $19 million in the Prior Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $165 million in the Current Quarter compared to $124 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.89 per mcfe in the Current Quarter compared to $0.84 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 2007 will range from $0.90 to $1.00 per mcfe produced.

Production Taxes. Production taxes were $56 million in the Current Quarter compared to $41 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.30 per mcfe in the Current Quarter compared to $0.28 per mcfe in the Prior Quarter. The $15 million increase in production taxes in the Current Quarter is due primarily to an increase in production of 40 bcfe, which more than offset the price decrease of approximately $0.26 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 oil and natural gas prices are higher. We expect production taxes for the fourth quarter of 2007 to range from $0.35 to $0.40 per mcfe based on NYMEX prices of $79.84 per barrel of oil and natural gas wellhead prices ranging from $6.70 to $7.80 per mcf.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties, were $62 million in the Current Quarter and $37 million in the Prior Quarter. General and administrative expenses were $0.33 and $0.25 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $19 million and $8 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. We anticipate that general and administrative expenses for the fourth quarter of 2007 will be between $0.33 and $0.40 per mcfe produced (including stock-based compensation ranging from $0.08 to $0.10 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 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock.

Chesapeake follows the full-cost method of accounting under which all costs associated with oil and natural gas 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 $76 million and $49 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $479 million and $344 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 $2.57 and $2.34 in the Current Quarter and in the Prior Quarter, respectively. The $0.23 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the fourth quarter of 2007 to be between $2.60 and $2.70 per mcfe produced.

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Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $44 million in the Current Quarter, compared to $27 million in the Prior Quarter. Depreciation and amortization of other assets was $0.24 and $0.18 per mcfe for the Current Quarter and the Prior Quarter, respectively. The increase in the Current Quarter was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment and drilling rig equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2006 and the Current Period. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 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 are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect the fourth quarter of 2007 depreciation and amortization of other assets to be between $0.18 and $0.20 per mcfe produced.

Interest and Other Income. Interest and other income was $1 million in the Current Quarter compared to $5 million in the Prior Quarter. The Current Quarter income consisted of $2 million of interest income, ($3) million related to losses of equity investees and $2 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, $2 million related to earnings of equity investees and $1 million of miscellaneous income.

Interest Expense. Interest expense increased to $116 million in the Current Quarter compared to $74 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2007	2006
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 161	$ 122
Capitalized interest	(67)	(49)
Realized (gain) loss on interest rate derivatives	(1)	2
Unrealized (gain) loss on interest rate derivatives	19	(3)
Amortization of loan discount and other	4	2
Total interest expense	$ 116	$ 74
Average long-term borrowings	$ 8,724	$ 6,525

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in both the Current Quarter and the Prior Quarter. We expect interest expense for the fourth quarter of 2007 to be between $0.55 and $0.60 per mcfe produced (before considering the effect of interest rate derivatives).

Income Tax Expense. Chesapeake recorded income tax expense of $228 million in the Current Quarter, compared to income tax expense of $335 million in the Prior Quarter. Our effective income tax rate was 38% in both the Current Quarter and the Prior Quarter. Most of our 2006 income tax expense was deferred, and we expect most of our fourth quarter 2007 income tax expense to be deferred.

Results of Operations - Nine Months Ended September 30, 2007 vs. September 30, 2006

General. For the Current Period, Chesapeake had net income of $1.148 billion, or $2.23 per diluted common share, on total revenues of $5.711 billion. This compares to net income of $1.532 billion, or $3.40 per diluted common share, on total revenues of $5.458 billion during the Prior Period.

Oil and Natural Gas Sales. During the Current Period, oil and natural gas sales were $4.164 billion compared to $4.190 billion in the Prior Period. In the Current Period, Chesapeake produced 510.1 bcfe at a weighted average price of $8.39 per mcfe, compared to 426.3 bcfe produced in the Prior Period at a weighted average price of $8.77 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of ($113) million and $453 million in the Current Period and Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenue of $195 million and increased production resulted in a $735 million increase, for a total increase in revenues of $540 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Period to the Current Period is primarily generated from the drillbit.

For the Current Period, we realized an average price per barrel of oil of $65.55, compared to $58.86 in the Prior Period (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.15

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and $8.66 in the Current Period and Prior Period, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $916 million, or $1.80 per mcfe, in the Current Period and $807 million, or $1.89 per mcfe, in the Prior Period.

Changes in oil and natural gas prices have a significant impact on our oil and natural gas 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 $47 million and $45 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 $7 million 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 Nine Months Ended September 30,			
	2007		2006	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	270,655	53%	233,078	55%
Fort Worth Barnett Shale	59,162	12	30,035	7
South Texas and Texas Gulf Coast	58,609	11	59,040	14
Permian and Delaware Basins	45,529	9	36,487	8
Ark-La-Tex	41,279	8	34,410	8
Appalachian Basin	34,845	7	33,268	8
Total production	510,079	100%	426,318	100%

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in the Current Period, compared to 91% in the Prior Period.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing sales and operating expenses are from third parties who are owners in Chesapeake-operated wells. Chesapeake recognized $1.446 billion in oil and natural gas marketing sales in the Current Period, with corresponding oil and natural gas marketing expenses of $1.394 billion, for a net margin before depreciation of $52 million. This compares to sales of $1.170 billion, expenses of $1.132 billion and a net margin before depreciation of $38 million in the Prior Period. In the Current Period, Chesapeake realized an increase in oil and natural gas marketing sales volumes related to the increase in production on Chesapeake-operated wells.

Service Operations Revenue and Operating Expenses. Service operations revenue and expenses consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired and built in 2006 and 2007. Chesapeake recognized $101 million in service operations revenue in the Current Period with corresponding service operations expense of $67 million, for a net margin before depreciation of $34 million. This compares to revenue of $98 million, expenses of $49 million and a net margin before depreciation of $49 million in the Prior Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $461 million in the Current Period compared to $364 million in the Prior Period. On a unit-of-production basis, production expenses were $0.90 per mcfe in the Current Period compared to $0.85 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 2007 will range from $0.90 to $1.00 per mcfe produced.

Production Taxes. Production taxes were $151 million in the Current Period compared to $130 million in the Prior Period. On a unit-of-production basis, production taxes were $0.30 per mcfe in both the Current Period and the Prior Period. The Prior Period included a $2 million accrual for certain severance tax claims and then a subsequent reversal of the cumulative $12 million accrual for such severance tax claims as a result of their dismissal. After adjusting for these items, there was an increase of $11 million in production taxes from the Prior Period. The $11 million increase is due to an increase in production of 84 bcfe, which more than offset the price decrease of approximately $0.28 per mcfe (excluding gains or losses on derivatives) and the increase in qualified production tax exemptions in Texas.

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for 2007 to range from $0.35 to $0.40 per mcfe based on NYMEX prices of $69.90 per barrel of oil and natural gas wellhead prices ranging from $6.80 to $7.90 per mcf.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our oil and natural gas properties, were $168 million in the Current Period and $99 million in the Prior Period. General and administrative expenses were $0.33 and $0.23 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $41 million and $21 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. We anticipate that general and administrative expenses for 2007 will be between $0.33 and $0.40 per mcfe produced (including stock-based compensation ranging from $0.08 to $0.10 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 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock.

Chesapeake follows the full-cost method of accounting under which all costs associated with oil and natural gas 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 $186 million and $119 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $1.314 billion and $977 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 $2.58 and $2.29 in the Current Period and in the Prior Period, respectively. The $0.29 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for 2007 to be between $2.50 and $2.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $120 million in the Current Period, compared to $74 million in the Prior Period. Depreciation and amortization of other assets was $0.24 and $0.17 per mcfe for the Current Period and the Prior Period, respectively. The increase in the Current Period was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment and drilling rig equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2006 and the Current Period. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 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 are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for 2007 to be between $0.20 and $0.24 per mcfe produced.

Employee Retirement Expense. Our former President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested equity awards, which consisted of options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock. As a result of this vesting, we incurred an expense of $55 million in the Prior Period.

Interest and Other Income. Interest and other income was $12 million in the Current Period compared to $20 million in the Prior Period. The Current Period income consisted of $6 million of interest income, $2 million related to earnings of equity investees and $4 million of miscellaneous income. The Prior Period income consisted of $3 million of interest income, $9 million related to earnings of equity investees, a $4 million gain on sale of assets and $4 million of miscellaneous income.

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Interest Expense. Interest expense increased to $279 million in the Current Period compared to $220 million in the Prior Period as follows:

	Nine Months Ended September 30, 2007	2006
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 443	$ 336
Capitalized interest	(192)	(119)
Realized (gain) loss on interest rate derivatives		(1)
Unrealized (gain) loss on interest rate derivatives	13	(1)
Amortization of loan discount and other	15	5
Total interest expense	$ 279	$ 220
Average long-term borrowings	$ 7,999	$ 6,125

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe for both the Current Period and the Prior Period. We expect interest expense for 2007 to be between $0.55 and $0.60 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investments. In the Current 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. In the Prior Period, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company common stock, realizing proceeds of $159 million and a gain of $117 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Income Tax Expense. Chesapeake recorded income tax expense of $704 million in the Current Period, compared to income tax expense of $963 million in the Prior Period. Our effective income tax rate was 38% in the Current Period compared to 38.6% in the Prior Period. The Prior Period included a $15 million adjustment in additional deferred income taxes related to the effect of Texas House Bill 3 which was signed into law in May 2006. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Prior Period. Most of our 2006 income tax expense was deferred, and we expect most of our 2007 income tax expense to be deferred.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $11 million in the Prior Period. The loss represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2006.

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 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments we acquire or issue after December 31, 2006. Adoption of SFAS 155 did not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. 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 February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. 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. 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.

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The FASB has announced that it plans to issue proposed staff guidance on accounting for convertible debt instruments that may be settled in cash upon conversion, including partial cash settlements. This accounting could 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 would 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 two debt series that would be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035 and our 2.5% Contingent Convertible Senior Notes due 2037. If the FASB adopts the guidance, it is expected to be effective for fiscal years starting after December 15, 2007. Companies would have to apply the guidance retrospectively to both existing and new instruments that fall within the scope of the guidance.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and natural gas reserve estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expected oil and natural gas 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 annual report on Form 10-K for the year ended December 31, 2006 and include:

- the volatility of oil and natural gas 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 oil and natural gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities,
- inability to effectively integrate and operate acquired companies and properties,
- unsuccessful exploration and development drilling,

- declines in the value of our oil and natural gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- lower oil and natural gas 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.

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

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2007, our oil and natural gas derivative instruments were comprised of swaps, knockout swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

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.

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which 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 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 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 oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

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

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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 oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) are included in oil and natural gas 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 oil and natural gas 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 recognized currently in oil and natural gas sales as unrealized gains (losses). The components of oil and natural gas sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	($ in millions)			
Oil and natural gas sales	$ 1,161	$ 953	$ 3,361	$ 2,930
Realized gains on oil and natural gas derivatives	286	301	916	807
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	73	67	(21)	116
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(28)	172	(92)	337
Total oil and natural gas sales	$ 1,492	$ 1,493	$ 4,164	$ 4,190

As of September 30, 2007, we had the following open oil and natural gas derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our oil and natural gas production for periods after September 2007:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2007 ($ in millions)
Natural Gas (mmbtu):								
Swaps:								
4Q 2007	99,340,000	$ 7.49	$	$	$	Yes	$	$ 41
1Q 2008	97,762,500	8.82				Yes		62
2Q 2008	57,102,500	7.99				Yes		21
3Q 2008	57,730,000	8.11				Yes		17
4Q 2008	57,730,000	8.70				Yes		22
1Q 2009	18,900,000	8.91				Yes		
2Q 2009	19,110,000	7.89				Yes		1
3Q 2009	19,320,000	8.00				Yes		1
4Q 2009	19,320,000	8.41				Yes		1
1Q 2010	6,300,000	8.57				Yes		(2)
2Q 2010	6,370,000	7.72				Yes		1
3Q 2010	6,440,000	7.80				Yes		
4Q 2010	6,440,000	8.10				Yes		
Basis Protection Swaps								
(Mid-Continent):								
4Q 2007	33,317,500				(0.26)	No		24

1Q 2008	33,215,000	(0.30)	No	28
2Q 2008	26,845,000	(0.25)	No	24
3Q 2008	27,140,000	(0.25)	No	21
4Q 2008	31,410,000	(0.28)	No	32
1Q 2009	26,100,000	(0.32)	No	19
2Q 2009	20,020,000	(0.28)	No	12
3Q 2009	20,240,000	(0.28)	No	10
4Q 2009	20,240,000	(0.28)	No	12
2Q 2012	4,550,000	(0.34)	No	1
3Q 2012	4,600,000	(0.34)	No	1
4Q 2012	1,550,000	(0.34)	No	

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2007 ($ in millions)
Basis Protection Swaps (Appalachian Basin):								
4Q 2007	9,200,000	$	$	$	$ 0.35	No	$	$ 1
1Q 2008	10,920,000				0.35	No		(2)
2Q 2008	10,920,000				0.35	No		
3Q 2008	11,040,000				0.35	No		
4Q 2008	11,040,000				0.35	No		
1Q 2009	9,000,000				0.31	No		(1)
2Q 2009	9,100,000				0.31	No		
3Q 2009	9,200,000				0.31	No		
4Q 2009	9,200,000				0.31	No		
1Q 2010	7,200,000				0.31	No		(1)
2Q 2010	7,280,000				0.31	No		
3Q 2010	7,360,000				0.31	No		
4Q 2010	7,360,000				0.31	No		
1Q 2011	7,200,000				0.32	No		(1)
2Q 2011	7,280,000				0.32	No		
3Q 2011	7,360,000				0.32	No		
4Q 2011	7,360,000				0.32	No		
Other Swaps:								
4Q 2007	16,350,000	7.19				No		8
1Q 2008	4,550,000	7.67				No		(1)
2Q 2008	6,050,000	8.47				No		5
3Q 2008	4,600,000	8.73				No		4
4Q 2008	4,600,000	8.73				No		2
1Q 2009[a]	4,500,000	8.73				No		(13)
1Q 2010[a]						No		(12)
Knockout Swaps:								
4Q 2007	17,210,000	9.13	5.79			No		32
1Q 2008	8,190,000	10.83	5.94			No		16
2Q 2008	60,380,000	9.15	6.21			No		26
3Q 2008	62,560,000	9.32	6.21			No		11
4Q 2008	55,240,000	9.91	6.20			No		6
1Q 2009	39,600,000	10.28	6.17			No		6
2Q 2009	37,310,000	8.73	6.18			No		(6)
3Q 2009	37,720,000	8.83	6.05			No		(10)
4Q 2009	37,720,000	9.41	6.11			No		(10)
Call Options:								
4Q 2007	15,700,000			9.06		No	19	(1)
1Q 2008	32,760,000			10.20		No	22	(14)
2Q 2008	31,850,000			10.25		No	21	(9)
3Q 2008	32,200,000			10.25		No	21	(16)
4Q 2008	30,980,000			10.26		No	20	(26)
1Q 2009	31,500,000			11.11		No	19	(24)
2Q 2009	29,120,000			11.13		No	18	(9)
3Q 2009	29,440,000			11.13		No	18	(12)
4Q 2009	29,440,000			11.13		No	18	(19)
1Q 2010	1,800,000			11.00		No		(2)
2Q 2010	1,820,000			11.00		No		(1)
3Q 2010	1,840,000			11.00		No	1	(1)
4Q 2010	1,840,000			11.00		No	1	(1)

1Q 2011	1,800,000	11.00	No		(1)
2Q 2011	1,820,000	11.00	No	1	(1)
3Q 2011	1,840,000	11.00	No	1	(1)
4Q 2011	1,840,000	11.00	No		(1)
1Q 2012	1,820,000	11.00	No		(1)
2Q 2012	1,820,000	11.00	No	1	(1)
3Q 2012	1,840,000	11.00	No	1	(1)
4Q 2012	1,840,000	11.00	No	1	(1)

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	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2007 ($ in millions)
Collars:								
4Q 2007	5,810,000	$	$ 7.26	$ 9.06	$	Yes	$	$ 3
1Q 2008	7,590,000		7.32	9.17		Yes		(1)
2Q 2008	2,730,000		7.50	9.68		Yes		1
3Q 2008	2,760,000		7.50	9.68		Yes		1
4Q 2008	2,760,000		7.50	9.68		Yes		
Other Collars:								
4Q 2007	13,830,000		7.08/5.28	8.80		No		6
1Q 2008	10,920,000		7.40/5.46	9.35		No		
1Q 2009	4,500,000		7.50/6.00	10.72		No		(2)
2Q 2009	4,550,000		7.50/6.00	10.72		No		1
3Q 2009	4,600,000		7.50/6.00	10.72		No		
4Q 2009	4,600,000		7.50/6.00	10.72		No		(1)
Total Natural Gas							183	274
Oil (bbls):								
Swaps:								
4Q 2007	828,000	67.11				Yes		(10)
1Q 2008	1,152,000	70.79				Yes		(9)
2Q 2008	1,183,000	70.25				Yes		(7)
3Q 2008	1,196,000	69.94				Yes		(6)
4Q 2008	828,000	69.12				Yes		(4)
1Q 2009	135,000	68.02				Yes		(1)
2Q 2009	136,500	67.84				Yes		(1)
3Q 2009	138,000	67.67				Yes		(1)
4Q 2009	138,000	67.54				Yes		(1)
Knockout Swaps:								
4Q 2007	368,000	71.43	55.00			No		(3)
1Q 2008	546,000	74.97	53.58			No		(2)
2Q 2008	546,000	75.16	53.58			No		(2)
3Q 2008	552,000	75.29	53.58			No		(2)
4Q 2008	736,000	76.69	55.19			No		(2)
1Q 2009	1,665,000	79.25	57.92			No		(1)
2Q 2009	1,683,500	79.29	57.92			No		(2)
3Q 2009	1,702,000	79.31	57.92			No		(1)
4Q 2009	1,702,000	79.31	57.92			No		(2)
Cap-Swaps:								
4Q 2007	368,000	78.53	56.25			No		
1Q 2008	273,000	77.60	55.00			No		
2Q 2008	273,000	77.60	55.00			No		
3Q 2008	276,000	77.60	55.00			No		
4Q 2008	276,000	77.60	55.00			No		
Call Options:								
4Q 2007	920,000			79.85		No	1	(2)
1Q 2008	455,000			81.00		No	2	(2)
2Q 2008	455,000			81.00		No	2	(2)

3Q 2008	460,000	81.00	No		2		(2)
4Q 2008	644,000	79.29	No		2		(3)
1Q 2009	540,000	75.00	No		3		(3)
2Q 2009	546,000	75.00	No		3		(3)
3Q 2009	552,000	75.00	No		3		(4)
4Q 2009	552,000	75.00	No		3		(3)
1Q 2010	450,000	75.00	No		2		(3)
2Q 2010	455,000	75.00	No		2		(3)
3Q 2010	460,000	75.00	No		2		(3)
4Q 2010	460,000	75.00	No		2		(3)
Total Oil					29		(93)
Total Natural Gas and Oil				$	212	$	181

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

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In 2006 and 2007, Chesapeake lifted a portion of its 2007, 2008 and 2009 hedges and as a result has approximately $435 million of deferred hedging gains as of September 30, 2007. These gains have been recorded in accumulated other comprehensive income or as an unrealized gain in oil and natural gas sales. For amounts originally recorded in other comprehensive income, the gain will be recognized in oil and natural gas sales in the month of the hedged production.

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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 September 30, 2007:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at September 30, 2007 ($ in millions)
Natural Gas (mmbtu):						
Swaps:						
4Q 2007	10,580,000	$ 4.82	$	$	Yes	$ (23)
1Q 2008	9,555,000	4.68			Yes	(31)
2Q 2008	9,555,000	4.68			Yes	(27)
3Q 2008	9,660,000	4.68			Yes	(29)
4Q 2008	9,660,000	4.66			Yes	(34)
1Q 2009	4,500,000	5.18			Yes	(16)
2Q 2009	4,550,000	5.18			Yes	(11)
3Q 2009	4,600,000	5.18			Yes	(12)
4Q 2009	4,600,000	5.18			Yes	(13)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(2)
2Q 2009	910,000		4.50	6.00	Yes	(2)
3Q 2009	920,000		4.50	6.00	Yes	(2)
4Q 2009	920,000		4.50	6.00	Yes	(2)
Total Natural Gas						$ (204)

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 September 30, 2007.

Based upon the market prices at September 30, 2007, we expect to transfer approximately $195 million (net of income taxes) of the gain 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 September 30, 2007 are expected to mature by December 31, 2012.

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

	2007 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ 345
Change in fair value of contracts	998
Fair value of contracts when entered into	(213)
Contracts realized or otherwise settled	(916)
Fair value of contracts when closed	(237)
Fair value of contracts outstanding, as of September 30	$ (23)

The change in the fair value of our derivative instruments since January 1, 2007 resulted from the settlement of derivatives for a realized gain, as well as an increase in natural gas prices. Derivative instruments reflected as current in the condensed consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and natural gas as of the condensed 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 September 30, 2007, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity ($ in billions)							
	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
Liabilities:								
Long-term debt - fixed-rate[(a)]	$	$	$	$	$	$ 9.027	$ 9.027	$ 9.068
Average interest rate						5.8%	5.8%	5.8%
Long-term debt - variable rate	$	$	$	$	$ 1.950	$	$ 1.950	$ 1.950
Average interest rate					6.6%		6.6%	6.6%

(a) This amount does not include the discount included in long-term debt of ($107) million and the premium for interest rate swaps of $2 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 derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to 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 $1 million, ($2) million, a nominal amount and $1 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Pursuant to SFAS 133, certain interest rate derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were ($19) million, $3 million, ($13) million and $1 million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

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As of September 30, 2007, the following 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:								
July 2005	November 2020	$ 1,750	6.929%	6 month LIBOR plus 180 basis points		Yes	$	$ (17)
September 2004	July 2013	$ 325	7.942%	6 month LIBOR plus 297 basis points		No		(1)
Floating to Fixed Swaps:								
August 2007	August 2009	$ 500	5.034%	3 month LIBOR		No		(4)
Call Options:								
June 2007	February 2008	$ 750	7.000%			No	5	(15)
Collars:								
August 2007	August 2010	$ 1,325			5.37% - 4.32%	No		(7)
								$ (44)

In the Current Period, we sold call options on five of our interest rate swaps and received $9 million in premiums. Two of the options expired unexercised in the Current Period.

In the Current Period, we closed eight interest rate swaps for a gain totaling $9 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 will pay Chesapeake 19 million and Chesapeake will pay the counterparties $30 million, which will yield 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 ($853 million at September 30, 2007) using an exchange rate of $1.4219 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as an asset of $17 million at September 30, 2007. The translation adjustment to notes payable is completely offset by the fair value of the cross currency swap and therefore there is no impact to the consolidated statement of operations. The remaining value of the cross currency swap related to future interest payments is reported in other comprehensive income.

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.

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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 annual report on Form 10-K for the year ended December 31, 2006. 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 annual report on Form 10-K for the year ended December 31, 2006. 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 September 30, 2007:

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)]
July 1, 2007 through July 31, 2007	303,403	$ 35.074		
August 1, 2007 through August 31, 2007	13,531	33.117		
September 1, 2007 through September 30, 2007	18,703	35.277		
Total	335,637	$ 35.006		

(a) Includes the deemed surrender to the company of 9,979 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 325,658 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***

Not applicable.

Item 5. ***Other Information***

Not applicable.

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Item 6. ***Exhibits***

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

Exhibit Number	Description
3.1.1	Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.3 to Chesapeake s Form 10-Q for the quarter ended March 31, 2007.
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed November 9, 2005.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake s Form 10-Q for the quarter ended March 31, 2005.
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed September 15, 2005.
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K dated June 30, 2006.
3.2	Chesapeake s Amended and Restated Bylaws. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed June 13, 2007.
4.1	Seventh Amended and Restated Credit Agreement dated November 2, 2007 among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C. as Co-Borrowers, Union Bank of California, N.A. as Administrative Agent, The Royal Bank of Scotland as Syndication Agent and Bank of America, N.A., SunTrust Bank and BNP Paribas as Co-Documentation Agents and the several lenders from time to time parties thereto. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s current report on Form 8-K dated November 8, 2007.
10.1.1 *	Chesapeake s 2003 Stock Incentive Plan, as amended.
10.1.18 *	Chesapeake s Amended and Restated Long Term Incentive Plan.
10.2.1	Employment Agreement dated as of October 1, 2007 between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Chesapeake s current report on Form 8-K filed October 5, 2007.
12*	Computation of Ratios of Earnings to Fixed Charges and to Combined Fixed Charges and Preferred Stock Dividends.
31.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

Management contract or compensatory plan or arrangement

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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: November 9, 2007

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