CHESAPEAKE ENERGY CORP
Form 10-Q
May 10, 2011
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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 March 31, 2011

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

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

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

(405) 848-8000

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

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

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

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

As of May 3, 2011, there were 657,664,995 shares of our common stock, $0.01 par value, outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	March 31, 2011	December 31, 2010
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 849	$ 102
Accounts receivable	2,317	1,974
Short-term derivative instruments	264	947
Deferred income tax asset	2	139
Other current assets	112	104
Total Current Assets	3,544	3,266
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	36,943	38,952
Unevaluated properties	14,200	14,469
Natural gas gathering systems and treating plants	1,379	1,545
Other property and equipment	3,885	3,726
Total Property and Equipment, at Cost	56,407	58,692
Less: accumulated depreciation, depletion and amortization	(26,698)	(26,314)
Total Property and Equipment, Net	29,709	32,378
OTHER ASSETS:		
Investments	1,228	1,208
Other long-term assets	319	327
Total Other Assets	1,547	1,535
TOTAL ASSETS	$ 34,800	$ 37,179
CURRENT LIABILITIES:		
Accounts payable	$ 2,227	$ 2,069
Short-term derivative instruments	216	15
Accrued interest	123	191
Other current liabilities	2,103	2,215
Total Current Liabilities	4,669	4,490
LONG-TERM LIABILITIES:		
Long-term debt, net	9,915	12,640
Deferred income tax liabilities	2,115	2,384
Long-term derivative instruments	2,380	1,693
Asset retirement obligations	302	301

Other long-term liabilities	424	407
Total Long-Term Liabilities	15,136	17,425
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized: 7,254,515 shares issued and outstanding	3,065	3,065
Common stock, $0.01 par value, 1,000,000,000 shares authorized, 659,020,115 and 655,251,275 shares issued	7	7
Paid-in capital	12,161	12,194
Retained earnings		190
Accumulated other comprehensive income (loss), net of tax of $130 million and $102 million	(212)	(168)
Less: treasury stock, at cost; 1,312,307 and 1,221,299 common shares	(26)	(24)
Total Stockholders Equity	14,995	15,264
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 34,800	$ 37,179

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 March 31, 2011	2010
	($ in millions, except per share data)	
REVENUES:		
Natural gas and oil sales	$ 494	$ 1,898
Marketing, gathering and compression sales	1,017	844
Service operations revenue	101	56
Total Revenues	1,612	2,798
OPERATING COSTS:		
Production expenses	238	207
Production taxes	45	48
General and administrative expenses	130	109
Marketing, gathering and compression expenses	985	815
Service operations expense	77	49
Natural gas and oil depreciation, depletion and amortization	358	308
Depreciation and amortization of other assets	68	50
Gains on sales of other property and equipment	(5)	
Total Operating Costs	1,896	1,586
INCOME (LOSS) FROM OPERATIONS	(284)	1,212
OTHER INCOME (EXPENSE):		
Interest expense	(7)	(25)
Earnings from equity investees	25	13
Losses on redemptions or exchanges of debt	(2)	(2)
Other income	2	2
Total Other Income (Expense)	18	(12)
INCOME (LOSS) BEFORE INCOME TAXES	(266)	1,200
INCOME TAX EXPENSE (BENEFIT):		
Current income taxes	6	
Deferred income taxes	(110)	462
Total Income Tax Expense (Benefit)	(104)	462
NET INCOME (LOSS)	(162)	738
Preferred stock dividends	(43)	(6)

NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (205)	$ 732
EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$ (0.32)	$ 1.17
Diluted	$ (0.32)	$ 1.14
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.075
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		
Basic	634	630
Diluted	634	647

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)

	Three Months Ended March 31,	
	2011	2010
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ (162)	$ 738
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	426	358
Deferred income tax expense (benefit)	(110)	462
Unrealized (gains) losses on derivatives	1,188	(342)
Stock-based compensation	40	32
Accretion of discount on contingent convertible notes	20	19
Gains on sales of other property and equipment	(5)	
Gains on equity investments	(5)	(13)
Losses on redemptions or exchanges of debt	2	2
Other	10	5
Change in assets and liabilities	(663)	(78)
Cash provided by operating activities	741	1,183
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(1,692)	(1,020)
Acquisitions of proved and unproved properties	(1,281)	(1,030)
Additions to other property and equipment	(431)	(279)
Proceeds from divestitures of proved and unproved properties	5,182	1,224
Proceeds from sales of other assets	428	56
Other	(3)	35
Cash provided by (used in) investing activities	2,203	(1,014)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	3,617	2,924
Payments on credit facilities borrowings	(7,323)	(2,944)
Proceeds from issuance of senior notes, net of offering costs	977	
Cash paid to redeem debt	(128)	
Cash paid for common stock dividends	(48)	(47)
Cash paid for preferred stock dividends	(43)	(6)
Cash received on financing derivatives	660	94
Net increase in outstanding payments in excess of cash balance	119	45
Other	(28)	(26)
Cash provided by (used in) financing activities	(2,197)	40
Net increase in cash and cash equivalents	747	209
Cash and cash equivalents, beginning of period	102	307

Cash and cash equivalents, end of period	$ 849	$ 516

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)

	Three Months Ended March 31,	
	2011	**2010**
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 41	$ 89
Income taxes, net of refunds received	$	$ (8)

SUPPLEMENTAL SCHEDULE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of March 31, 2011 and 2010, dividends payable on our common and preferred stock were $90 million and $53 million, respectively.

For the three months ended March 31, 2011 and 2010, natural gas and oil properties were adjusted by $22 million and $1 million, respectively, as a result of an increase in accrued costs.

For the three months ended March 31, 2011 and 2010, other property and equipment were adjusted by $5 million and $1 million, respectively, as a result of an increase in accrued costs.

As of March 31, 2011 and 2010, we had recorded $202 million and $183 million, respectively, as a result of various accrued liabilities related to the purchase of proved and unproved properties and other assets.

During the three months ended March 31, 2010, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $11 million in aggregate principal amount for an aggregate of 298,500 shares of our common stock in privately negotiated exchanges.

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)

	Three Months Ended March 31,	
	2011	2010
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$ 3,065	$ 466
COMMON STOCK:		
Balance, beginning of period	7	6
Exchange of convertible notes for 0 and 298,500 shares of common stock		
Stock-based compensation		1
Balance, end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,194	12,146
Stock-based compensation	50	57
Repurchase of 2.25% contingent convertible notes	(21)	
Exchange of convertible notes for 0 and 298,500 shares of common stock		9
Exercise of stock options	1	1
Dividends on common stock	(48)	(47)
Dividends on preferred stock	(15)	(6)
Balance, end of period	12,161	12,160
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	190	(1,261)
Net income (loss)	(162)	738
Cumulative effect of accounting change, net of income taxes of $89 million		(142)
Dividends on preferred stock	(28)	
Balance, end of period		(665)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(168)	102
Hedging activity	(47)	166
Investment activity	3	(3)
Balance, end of period	(212)	265
TREASURY STOCK COMMON:		
Balance, beginning of period	(24)	(15)
Purchase of 93,318 and 70,177 shares for company benefit plans	(2)	(2)
Release of 2,310 and 4,162 shares for company benefit plans		

Balance, end of period	(26)	(17)
NONCONTROLLING INTEREST:		
Balance, beginning of period		897
Deconsolidation of investment in Chesapeake Midstream Partners		(897)
Balance, end of period		
TOTAL STOCKHOLDERS EQUITY	$ 14,995	$ 12,216

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 (LOSS)

(Unaudited)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	($ in millions)	
Net income (loss)	$ (162)	$ 738
Other comprehensive income (loss), net of income tax:		
Change in fair value of derivative instruments, net of income taxes of $3 million and $152 million	5	249
Reclassification of gain on settled contracts, net of income taxes of ($28) million and ($53) million	(46)	(87)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($4) million and $2 million	(6)	4
Unrealized gain (loss) on marketable securities, net of income taxes of $2 million and ($2) million	3	(3)
Comprehensive income (loss)	$ (206)	$ 901

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 (Chesapeake or the company) and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission (SEC). Chesapeake s annual report on Form 10-K for the year ended December 31, 2010 (2010 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 accompanying condensed consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. The results for the three months ended March 31, 2011 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three months ended March 31, 2011 (the Current Quarter) and the three months ended March 31, 2010 (the Prior Quarter).

Cumulative Effect of Accounting Change

Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we ceased consolidating our 50/50 midstream joint venture with Global Infrastructure Partners within our financial statements and began to account for the joint venture under the equity method (see Note 9). Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our condensed consolidated statement of equity for the Prior Quarter. This charge reflects the difference between the carrying value of our initial investment in the joint venture, which was recorded at carryover basis as an entity under common control, and the fair value of our equity in the joint venture as of the formation date.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties and income taxes to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2010 Form 10-K.

2. Financial Instruments and Hedging Activities

Natural Gas and Oil Derivatives

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of March 31, 2011 and December 31, 2010, our natural gas and oil derivative instruments consisted of the following types of instruments:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.

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 a certain pre-determined knockout price.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

The estimated fair values of our natural gas and oil derivative instruments as of March 31, 2011 and December 31, 2010 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	March 31, 2011		**December 31, 2010**	
	Volume	**Fair Value ($ in millions)**	**Volume**	**Fair Value ($ in millions)**
Natural gas (bbtu):				
Fixed-price swaps	911,041	$ 587	1,035,134	$ 1,307
Call options	1,477,742	(922)	1,477,742	(701)
Put options	(42,220)	(44)	(51,220)	(59)
Basis protection swaps	252,360	(57)	173,691	(55)
Total natural gas	2,598,923	(436)	2,635,347	492
Oil (mbbl):				
Fixed-price swaps	14,092	(50)	4,385	(31)
Call options	72,126	(1,758)	64,226	(1,129)
Fixed-price knockout swaps	1,557	(2)	1,827	19
Total oil	87,775	(1,810)	70,438	(1,141)
Total estimated fair value		$ (2,246)		$ (649)

Pursuant to accounting guidance for derivatives, certain derivatives qualify for designation as cash flow hedges. Following this guidance, 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 accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations within natural gas and oil sales.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The components of natural gas and oil sales for the Current Quarter and the Prior Quarter are presented below.

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	($ in millions)	
Natural gas and oil sales	$ 1,188	$ 1,184
Gains (losses) on natural gas and oil derivatives	(704)	720
Gains (losses) on ineffectiveness of cash flow hedges	10	(6)
Total natural gas and oil sales	$ 494	$ 1,898

Based upon the market prices at March 31, 2011, we expect to transfer approximately $1 million (net of income taxes) of loss included in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of March 31, 2011 are expected to mature by December 31, 2022.

We have a multi-counterparty secured hedging facility with 12 counterparties that have committed to provide approximately 5.6 tcfe of hedging capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. In February 2011, we amended the agreement for the hedge facility primarily to allow us to protect our natural gas liquids production from price volatility and to allow for greater flexibility when hedging our anticipated production. As of March 31, 2011, we had hedged a total of 2.9 tcfe of our future production under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based hedging capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based hedging limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas, oil and natural gas liquids hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into hedges with the company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of March 31, 2011 and December 31, 2010, our interest rate derivative instruments consisted of the following types of instruments:

Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facilities borrowings.

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate a pre-determined open swap on a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a pre-determined swap with us on a specific date.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The notional amount of debt hedged and the estimated fair value of our interest rate derivatives outstanding as of March 31, 2011 and December 31, 2010 are provided below.

	March 31, 2011		December 31, 2010	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 2,400	$ (79)	$ 1,900	$ (54)
Call options	250		250	(2)
Swaptions	100		500	(13)
Total	$ 2,750	$ (79)	$ 2,650	$ (69)

For interest rate derivative instruments designated as fair value hedges, the fair values of the hedges are recorded on the condensed consolidated balance sheets as assets or liabilities, with corresponding offsetting adjustments to the debt s carrying value. Our qualifying interest rate swaps are considered 100% effective and therefore no ineffectiveness was recorded for the periods presented above. Changes in the fair value of non-qualifying interest rate derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are currently reported in the condensed consolidated statements of operations within interest expense.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the condensed consolidated statements of operations. The components of interest expense for the Current Quarter and the Prior Quarter are presented below.

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	($ in millions)	
Interest expense on senior notes	$ 177	$ 192
Interest expense on credit facilities	21	12
Capitalized interest	(205)	(161)
(Gains) losses on interest rate derivatives	(1)	(30)
Amortization of loan discount and other	15	12
Total interest expense	$ 7	$ 25

We have terminated certain fair value hedges related to senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next ten years, we will recognize $35 million in gains related to such transactions.

Foreign Currency Derivatives

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

sheet as a liability of $7 million at March 31, 2011. The euro-denominated debt in long-term debt has been adjusted to $851 million at March 31, 2011 using an exchange rate of $1.4183 to 1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

In accordance with accounting guidance for derivatives and hedging, 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. Derivative instruments reflected as current in the condensed consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.

The following table presents the fair value and location of each classification of derivative instrument as disclosed in the condensed consolidated balance sheets as of March 31, 2011 and December 31, 2010, on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value March 31, 2011	Fair Value December 31, 2010
		($ in millions)	
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 243	$ 307
Commodity contracts	Long-term derivative instruments	21	12
Total		264	319
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	295	921
Commodity contracts	Long-term derivative instruments	219	229
Total		514	1,150
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(83)	(59)
Commodity contracts	Long-term derivative instruments	(56)	
Interest rate contracts	Long-term derivative instruments	(31)	(25)
Foreign currency contracts	Long-term derivative instruments	(7)	(43)
Total		(177)	(127)
Derivatives not designated as hedging instruments:			

Commodity contracts	Short-term derivative instruments	(407)	(222)
Commodity contracts	Long-term derivative instruments	(2,478)	(1,837)
Interest rate contracts	Short-term derivative instruments		(15)
Interest rate contracts	Long-term derivative instruments	(48)	(29)
Total		(2,933)	(2,103)
Total derivative instruments		$ (2,332)	$ (761)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

A consolidated summary of the effect of derivative instruments on the condensed consolidated statements of operations for the Current Quarter and the Prior Quarter is provided below, separating fair value, cash flow and non-qualifying derivatives.

The following table presents the gain (loss) recognized in the statement of operations related to instruments designated as fair value derivatives as well as the corresponding hedged items:

Fair Value Derivatives	Location of Gain (Loss)	Three Months Ended March 31, 2011	2010
		($ in millions)	
Interest rate contracts	Interest expense	$ 6	$ 8
Senior notes hedged	Interest expense	$ (13)	$ (10)

The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) related to instruments designated as cash flow derivatives:

Cash Flow Derivatives	Location of Gain (Loss)	Three Months Ended March 31, 2011	2010
		($ in millions)	
Gain (Loss) Recognized in AOCI (Effective Portion)			
Commodity contracts	AOCI	$ 16	$ 405
Foreign currency contracts	AOCI	(18)	2
		$ (2)	$ 407
Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			
Commodity contracts	Natural gas and oil sales	$ 74	$ 140
Gain (Loss) Recognized in Income			
Commodity contracts			
Ineffective Portion	Natural gas and oil sales	$ 10	$ (6)
Amount initially excluded from effectiveness testing	Natural gas and oil sales	22	36
		$ 32	$ 30

The following table presents the gain (loss) recognized in the statement of operations related to instruments not qualifying as cash flow or fair value derivatives:

Non-Qualifying Derivatives	Location of Gain (Loss)	Three Months Ended March 31, 2011	2010
		($ in millions)	
Commodity contracts	Natural gas and oil sales	$ (800)	$ 544
Interest rate contracts	Interest expense	(5)	22
	Total	$ (805)	$ 566

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Credit Risk

Derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. On March 31, 2011, our commodity and interest rate derivative instruments were spread among 13 counterparties. Additionally, our multi-counterparty secured hedging facility described above includes 12 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for all of our commodity hedging.

3. Contingencies and Commitments

Litigation

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company s July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The defendants motion to dismiss was denied on September 2, 2010. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company s directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case. The derivative action is stayed pursuant to stipulation. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the securities class action case, which is at an early stage.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal.

The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management s estimates.

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Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to reduce and mitigate such environmental risks. 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 March 31, 2011. There are, however, pending against us enforcement actions related to alleged methane migration in Pennsylvania and compliance with Clean Water Act permitting requirements in West Virginia, as well as an investigation by the Pennsylvania Department of Environmental Protection of a recent well control incident. While these actions may result in monetary sanctions, we do not expect that they will have a material adverse effect on our operations.

Rig Leases

In a series of transactions since 2006, our drilling subsidiaries have sold 89 drilling rigs and related equipment for $754 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to service operations expense over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the rigs at the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew the lease for negotiated new terms at the expiration of the lease. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2011, the minimum aggregate undiscounted future rig lease payments were approximately $468 million.

Compressor Leases

Through various transactions since 2007, our compression subsidiary has sold 2,234 compressors, a significant portion of its compressor fleet, for $517 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to marketing, gathering and compression expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew the lease for negotiated new terms at the expiration of the lease. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2011, the minimum aggregate undiscounted future compressor lease payments were approximately $415 million.

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Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from 2011 to 2099. 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. The aggregate undiscounted amounts of such required demand payments are presented below:

	March 31, 2011 ($ in millions)
2011	$ 265
2012	487
2013	549
2014	576
2015	568
After 2015	3,780
Total	$ 6,225

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 50 rigs with terms of four months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2011, the aggregate undiscounted minimum future drilling rig commitment was approximately $182 million.

Natural Gas and Oil Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short-term in nature. We have also committed to purchase any natural gas and oil associated with certain volumetric production payment transactions. The purchase commitments are based on market prices at the time of production, and the purchased natural gas and oil is resold.

Minimum Volume Commitments

We are a party to two natural gas gathering agreements with a subsidiary of Chesapeake Midstream Partners, L.P. (see Note 9), pursuant to which we have committed to deliver specified minimum volumes of natural gas. Annually and at the end of the term, Chesapeake will be invoiced for any shortfalls in such volume deliveries at the rate specified in the agreement. Volume commitments remaining under the agreement relating to our Barnett Shale natural gas production as of March 31, 2011 were as follows:

	Bcf
2011	248

2012	325
2013	338
2014	351
2015	365
After 2015[(a)]	1,321
Total	2,948

(a) Final commitment period is for the six months ending June 30, 2019.

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Volume commitments remaining under the agreement relating to our Haynesville Shale natural gas production as of March 31, 2011 were as follows:

	Bcf
2011	60
2012	118
2013	135
Total	313

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with our partners (Statoil, Total and CNOOC), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas for certain designated time periods.

Other Commitments

As of March 31, 2011, we had made commitments to acquire additional proved and unproved properties in various transactions during the next twelve months for approximately $400 million.

4. Net Income Per Share

Accounting guidance for earnings per share (EPS) requires presentation of basic and diluted earnings per share on the face of the statements of operations for all entities with complex capital structures as well as a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

For the Current Quarter, the following securities and associated adjustments to net income, consisting of dividends on our cumulative convertible preferred stock, unvested restricted stock grants and outstanding stock options were not included in the calculation of diluted EPS, as the effect was antidilutive.

	Net Income Adjustments ($ in millions)	Shares (in millions)
Three Months Ended March 31, 2011:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 22	56
5.75% cumulative convertible preferred stock (series A)	$ 16	39
5.00% cumulative convertible preferred stock (series 2005B)	$ 3	5
4.50% cumulative convertible preferred stock	$ 3	6

Unvested restricted stock	$	8
Outstanding stock options	$	1

For the Prior Quarter, all outstanding securities that were convertible into common stock were included in the calculation of diluted EPS.

As a result of the net loss to common stockholders for the Current Quarter, both basic weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares outstanding, which are used in computing diluted EPS, were 634 million shares. The basic and diluted loss per common share was $0.32.

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(Unaudited)

A reconciliation of basic EPS and diluted EPS for the Prior Quarter is as follows:

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended March 31, 2010:			
Basic EPS	$ 732	630	$ 1.17
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 5.00% cumulative convertible preferred stock (series 2005B)	3	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	3	6	
Unvested restricted stock		5	
Outstanding stock options		1	
Diluted EPS	$ 738	647	$ 1.14

5. Stockholders Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares outstanding for the three months ended March 31, 2011 and 2010:

	2011	2010
	(in thousands)	
Shares outstanding at January 1	655,251	648,549
Restricted stock issuances (net of forfeitures)	3,587	2,842
Stock option exercises	182	133
Convertible note exchanges		299
Shares outstanding at March 31	659,020	651,823

In the Prior Quarter, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. The difference between the allocated debt value of the notes that were exchanged and the fair value of the common stock issued resulted in a $2 million loss (including a nominal amount of deferred charges associated with the exchanges).

Preferred Stock

The following reflects our preferred shares outstanding for the three months ended March 31, 2011 and 2010:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)	5.00% (2005)
			(in thousands)		
Shares outstanding at January 1, 2011 and March 31, 2011	1,500	1,100	2,559	2,096	
Shares outstanding at January 1, 2010 and March 31, 2010			2,559	2,096	5

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Dividends

Dividends declared on our common stock and preferred stock are reflected as adjustments to retained earnings to the extent a surplus of retained earnings will exist after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, such payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

Dividends on our outstanding preferred stock are payable quarterly in cash, common stock or a combination thereof.

Stock-Based Compensation

Chesapeake s stock-based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value at the date of the grant. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, production expenses, marketing, gathering and compression expenses or service operations expense. We recorded the following stock-based compensation during the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2011	2010
	($ in millions)	
Natural gas and oil properties	$ 31	$ 37
General and administrative expenses	23	22
Production expenses	9	10
Marketing, gathering and compression expenses	5	4
Service operations expense	3	2
Total	$ 71	$ 75

Restricted Stock. Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four or five years from the date of grant for employees and three years for non-employee directors.

A summary of the changes in unvested shares of restricted stock for the three months ended March 31, 2011 is presented below:

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value

Unvested shares as of January 1, 2011	21,375	$ 28.68
Granted	4,792	$ 26.76
Vested	(2,891)	$ 27.45
Forfeited	(170)	$ 27.41
Unvested shares as of March 31, 2011	23,106	$ 28.45

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The aggregate intrinsic value of restricted stock vested during the Current Quarter was approximately $76 million based on the stock price at the time of vesting.

As of March 31, 2011, there was $416 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately two years.

The vesting of certain restricted stock grants could result 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 both the Current Quarter and the Prior Quarter, we recognized a reduction in tax benefits related to restricted stock of $1 million, which was recorded as an adjustment to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options. We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and vested over a four-year period. All of our outstanding stock options are fully vested and exercisable.

The following table provides information related to stock option activity for the three months ended March 31, 2011:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in millions)
Outstanding at January 1, 2011	1,808	$ 8.90	2.03	$ 31
Exercised	(185)	$ 7.02		
Forfeited/canceled		$		
Outstanding and exercisable at March 31, 2011	1,623	$ 9.12	1.88	$ 40

(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.

There is no remaining unrecognized compensation cost related to unvested stock options.

During both the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to stock options of $1 million, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

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6. Debt

Our long-term debt consisted of the following at March 31, 2011 and December 31, 2010:

	March 31, 2011	December 31, 2010
	($ in millions)	
7.625% senior notes due 2013	$ 500	$ 500
9.5% senior notes due 2015	1,425	1,425
6.25% euro-denominated senior notes due 2017[a]	851	796
6.5% senior notes due 2017	1,100	1,100
6.875% senior notes due 2018	600	600
7.25% senior notes due 2018	800	800
6.625% senior notes due 2020	1,400	1,400
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	
2.75% contingent convertible senior notes due 2035[b]	451	451
2.5% contingent convertible senior notes due 2037[b]	1,378	1,378
2.25% contingent convertible senior notes due 2038[b]	612	752
Corporate revolving bank credit facility		3,612
Midstream revolving bank credit facility		94
Discount on senior notes[c]	(707)	(777)
Interest rate derivatives[d]	5	9
Total long-term debt	$ 9,915	$ 12,640

(a) The principal amount shown is based on the exchange rate of $1.4183 to 1.00 and $1.3269 to 1.00 as of March 31, 2011 and December 31, 2010, respectively. See Note 2 for information on our related foreign currency derivatives.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the first quarter of 2011, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2011 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period in which contingent interest may be payable for the contingent convertible senior notes are as follows:

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Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.62	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.26	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Included in this discount is $645 million at March 31, 2011 and $711 million at December 31, 2010 associated with the equity component of our contingent convertible senior notes. This discount is based on an effective yield method.

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

Senior Notes

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 to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries, excluding Chesapeake Midstream Development, L.P. (CMD) and its subsidiaries. See Note 11 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Our senior notes are governed by indentures containing covenants that limit our ability and our subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance. These rates for our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038 are 6.86%, 8.0% and 8.0%, respectively.

During the Current Quarter, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.

During the Current Quarter, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $129 million, including accrued interest. Associated with these repurchases, we recognized a loss of $2 million in the Current Quarter.

During the Prior Quarter, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $11 million in aggregate principal amount for an aggregate of 298,500 shares of our common stock in privately negotiated exchanges. Associated with these exchanges, we recognized a loss of $2 million in the Prior Quarter.

No scheduled principal payments are required under our senior notes until 2013 when $500 million is due.

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Bank Credit Facilities

We utilize two revolving bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility[(a)]	Midstream Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	July 2015
Borrowing capacity	$ 4,000	$ 300
Amount outstanding as of March 31, 2011	$	$
Letters of credit outstanding as of March 31, 2011	$ 13	$

(a) Borrower is Chesapeake Exploration, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C., a wholly owned subsidiary of Chesapeake Midstream Development, L.P.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities contains 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.

Corporate Credit Facility

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at March 31, 2011. 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 $50 million or more, 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 of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries.

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Midstream Credit Facility

Our $300 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly owned subsidiaries (the restricted subsidiaries) of CMD, itself a wholly owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.75% to 2.25% per annum according to the most recent leverage ratio described below or (ii) the Eurodollar rate, which is based on the LIBOR plus a margin that varies from 2.75% to 3.25% per annum according to the most recent leverage ratio. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our master limited partnership midstream affiliate, Chesapeake Midstream Partners, L.P. As of December 21, 2010, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2010 due to the sale of the Springridge gathering system, as it was classified as a material disposition of assets. We were in compliance with all covenants under the agreement at March 31, 2011. If CMD or its restricted subsidiaries should fail to perform their 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. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Other Financings

In 2009, we financed 113 real estate surface assets in the Barnett Shale area for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the condensed consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in 2010. As of March 31, 2011, 111 assets were leased and the minimum aggregate undiscounted future lease payments were approximately $824 million. This obligation is recorded in other long-term liabilities on our condensed consolidated balance sheets.

In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for net proceeds of approximately $54 million with a five-year term loan which has a floating rate of prime plus 275 basis points. At our option, we may prepay in full without penalty beginning in year four. This obligation is recorded in other long-term liabilities on our condensed consolidated balance sheets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Segment Information

In accordance with accounting guidance for disclosures about segments of an enterprise and related information, we have two reportable operating segments. Our exploration and production operating segment and natural gas and oil marketing, gathering and compression operating segment are managed separately because of the nature of their products and services. The exploration and production operating segment is responsible for finding and producing natural gas and oil. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas and oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations which are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties. Our drilling rig and trucking service operations are included in Other Operations in the table below.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas and oil related to Chesapeake s ownership interests by the marketing, gathering and compression operating segment are reflected as exploration and production revenues. Such amounts totaled $1.204 billion and $1.061 billion for the Current Quarter and the Prior Quarter, respectively. The following table presents selected financial information for Chesapeake s operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)		
Three Months Ended March 31, 2011:					
Revenues	$ 494	$ 2,221	$ 248	$ (1,351)	$ 1,612
Intersegment revenues		(1,204)	(147)	1,351	
Total revenues	$ 494	$ 1,017	$ 101	$	$ 1,612
Income (loss) before income taxes	$ (297)	$ 87	$ 22	$ (78)	$ (266)
Three Months Ended March 31, 2010:					
Revenues	$ 1,898	$ 1,905	$ 170	$ (1,175)	$ 2,798
Intersegment revenues		(1,061)	(114)	1,175	
Total revenues	$ 1,898	$ 844	$ 56	$	$ 2,798
Income (loss) before income taxes	$ 1,177	$ 87	$ 1	$ (65)	$ 1,200
As of March 31 2011:					
Total assets	$ 31,223	$ 3,400	$ 899	$ (722)	$ 34,800
As of December 31, 2010:					
Total assets	$ 33,560	$ 3,458	$ 854	$ (693)	$ 37,179

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8. Divestitures

Fayetteville Shale Asset Sale

On March 31, 2011, we sold all of our Fayetteville Shale assets in Central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE: BHP; ASX: BHP), for net proceeds of approximately $4.65 billion in cash. The sold properties consisted of approximately 487,000 net acres of leasehold, current net production of approximately 415 million cubic feet of natural gas equivalent per day and midstream assets consisting of approximately 420 miles of pipeline. As part of the transaction, Chesapeake has agreed to provide technical and business services for up to one year for BHP Billiton s Fayetteville properties for an agreed-upon fee.

Joint Ventures

As of March 31, 2011, we had entered into six significant joint ventures pursuant to which we sold a portion of our leasehold in six different plays and received cash and commitments for future drilling and completion cost sharing. These transactions have allowed us to recover much or all of our initial leasehold investments in the plays, reduce our ongoing capital costs, reduce future DD&A expense and reduce future risks. The transactions are detailed below.

On February 11, 2011, we entered into a joint venture with CNOOC International Limited, a wholly owned subsidiary of CNOOC Limited (CNOOC), to develop our leasehold overlaying the Niobrara Shale, Codell and other formations in the Powder River and DJ Basins in northeast Colorado and southeast Wyoming. Under the terms of the joint venture, CNOOC acquired a 33.3% undivided interest in approximately 800,000 net acres of our Powder River and DJ Basins leasehold. We received $570 million in cash at closing, and CNOOC agreed to fund 66.7% of our share of drilling and completion costs in the Powder River and DJ Basins until an additional $697 million has been paid, which we expect to occur by year-end 2014. CNOOC also has the right to a 33.3% participation in any additional leasehold we acquire in the Powder River and DJ Basins at cost plus a fee.

On November 15, 2010, we entered into a joint venture with CNOOC International Limited to develop our Eagle Ford and Pearsall Shales leasehold in South Texas. Under the terms of the joint venture, CNOOC acquired a 33.3% undivided interest in approximately 600,000 net acres of our Eagle Ford and Pearsall Shales leasehold along with 18.2 bcfe of estimated proved reserves. We received $1.12 billion in cash at closing, and CNOOC agreed to fund 75% of our share of drilling and completion costs in the Eagle Ford and Pearsall Shales until an additional $1.08 billion has been paid, which we expect to occur by year-end 2012. In addition, CNOOC has the right to a 33.3% participation in any additional leasehold we acquire in the Eagle Ford and Pearsall Shales at cost plus a fee.

On January 25, 2010, we entered into a joint venture with Total E&P USA, Inc., a wholly owned subsidiary of Total S.A. (Total), to develop our Barnett Shale leasehold in north-central Texas. Under the terms of the joint venture, Total acquired a 25% undivided interest in approximately 270,000 net acres of our Barnett Shale leasehold along with 840 bcfe of estimated proved reserves. We received approximately $800 million in cash at closing (plus $78 million of drilling and completion carries due from the effective date of the transaction to the closing date), and Total agreed to fund 60% of our share of future drilling and completion costs in the Barnett Shale until $1.45 billion has been paid, which we expect to occur by year-end 2013. In addition, Total has the right to a 25% participation in any additional leasehold we acquire in the Barnett Shale at cost plus a fee.

On November 25, 2008, we entered into a joint venture with Statoil to develop our Marcellus Shale leasehold in Appalachia. Under the terms of the joint venture, Statoil acquired a 32.5% undivided interest in approximately 1.8 million net acres of our Marcellus Shale leasehold along with 2.5 bcfe of estimated proved reserves. We received $1.25 billion in cash at closing, and Statoil agreed to fund 75% of our share of drilling and completion costs in the Marcellus Shale until an additional $2.125 billion has been paid, which we expect to occur by year-end 2012. In addition, Statoil has the right to a 32.5% participation in any additional leasehold we acquire in the Marcellus Shale at cost plus a fee.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

On September 5, 2008, we entered into a joint venture with BP America Production Company, a wholly owned subsidiary of BP plc (BP), to develop our Fayetteville Shale leasehold in Arkansas. Under the terms of the joint venture, BP acquired a 25% undivided interest in approximately 540,000 net acres of our Fayetteville Shale leasehold along with 161.8 bcfe of estimated proved reserves. We received $1.1 billion in cash at closing, and BP paid an additional $800 million by funding 100% of Chesapeake s 75% share of drilling and completion costs during 2008 and 2009. BP had the right to a 25% participation in any additional leasehold we acquired in the Fayetteville Shale at cost plus a fee until we sold all of our Fayetteville Shale assets on March 31, 2011 to BHP Billiton Petroleum.

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company (PXP) to develop our Haynesville and Bossier Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, PXP acquired a 20% undivided interest in approximately 550,000 net acres of our Haynesville and Bossier Shale leasehold along with 22.9 bcfe of estimated proved reserves. We received $1.65 billion in cash at closing, and PXP agreed to fund 50% of our share of drilling and completion costs in the Haynesville and Bossier Shale over a multi-year period, up to an additional $1.65 billion. In August 2009, Chesapeake and PXP amended their agreement to accelerate the payment of PXP s remaining drilling and completion cost carries as of September 30, 2009, in exchange for an approximate 12% reduction in the total amount of carry obligations due to Chesapeake. As a result, on September 29, 2009, Chesapeake received $1.1 billion in cash from PXP, and beginning in the 2009 fourth quarter Chesapeake and PXP each began paying their proportionate working interest costs on drilling. In addition, PXP has the right to a 20% participation in any additional leasehold we acquire in the Haynesville and Bossier Shales at cost plus a fee.

During the Current Quarter and the Prior Quarter, our drilling and completion costs included the benefit of approximately $527 million and $281 million, respectively, in drilling and completion carries associated with our joint venture agreements with CNOOC, Total and Statoil as follows:

Primary Play	Joint Venture Partner	Joint Venture Agreement Date	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
			($ in millions)	
Niobrara	CNOOC	February 2011	$ 24	$
Eagle Ford	CNOOC	November 2010	122	
Barnett	Total	January 2010	137	189
Marcellus	Statoil	November 2008	244	92
			$ 527	$ 281

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(Unaudited)

During the Current Quarter and the Prior Quarter, as part of our joint venture agreements with CNOOC, Total, Statoil and Plains Exploration & Production Company, we sold interests in additional leasehold in the Eagle Ford, Barnett, Marcellus and Haynesville shale plays for approximately $224 million and $245 million, respectively.

For accounting purposes, cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Volumetric Production Payments

From time to time, we choose to monetize certain of our producing assets in our more mature producing regions through the sale of volumetric production payments. We retain drilling rights on the properties below currently producing intervals and outside of producing well bores. We also retain all production beyond the specified volumes sold in the transaction.

We have completed the following volumetric production payment (VPP) transactions since 2007:

Date of VPP	Region	Proceeds ($ in millions)	Proved Reserves (at time of sale) (bcfe)	$ / mcfe	Original Term (years)
September 2010	Barnett Shale	$ 1,150	390	$ 2.93	5
June 2010	Permian Basin	335	38	$ 8.73	10
February 2010	East Texas and the Texas Gulf Coast	180	46	$ 3.95	10
August 2009	South Texas	370	68	$ 5.46	7.5
December 2008	Anadarko and Arkoma Basins	412	98	$ 4.19	8
August 2008	Anadarko Basin	600	93	$ 6.38	11
May 2008	Texas, Oklahoma and Kansas	622	94	$ 6.53	11
December 2007	Kentucky and West Virginia	1,100	208	$ 5.29	15
		$ 4,769	1,035	$ 4.61	

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized, and our proved reserves were reduced accordingly.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Investments

At March 31, 2011 and December 31, 2010, we had the following investments:

	Approximate % Owned	Accounting Method	Carrying Value March 31, 2011	Carrying Value December 31, 2010
			($ in millions)	
Chesapeake Midstream Partners, L.P.	42%	Equity	$ 695	$ 695
Frac Tech Holdings, LLC	26%	Equity	341	311
Chaparral Energy, Inc.	20%	Equity	130	133
Gastar Exploration Ltd.	11%	Cost	33	29
Other		Cost/Equity	29	40
			$ 1,228	$ 1,208

Chesapeake Midstream Partners, L.P. On September 30, 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, Chesapeake contributed certain natural gas gathering and processing assets to, and GIP purchased a 50% interest in, a new joint venture entity. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM) completed an initial public offering of 24,437,500 common units (including 3,187,500 common units issued pursuant to the exercise of the underwriters over-allotment option on August 3, 2010) representing limited partner interests and received gross offering proceeds of approximately $513 million at an initial offering price of $21.00 per unit less approximately $38 million for underwriting discounts and commissions, structuring fees and offering expenses. Common units owned by public security holders represent 17.7% of all outstanding limited partner interests, and Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests. The limited partners, collectively, have a 98.0% interest in CHKM and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2.0% interest in CHKM.

During the Current Quarter, we recorded positive equity method adjustments of $17 million for our share of CHKM s income and recorded accretion adjustments of $3 million for our share of equity in excess of cost. In addition, in the Current Quarter, we received a cash distribution of $20 million from CHKM. The carrying value of our investment in CHKM is less than our underlying equity in net assets by approximately $234 million as of March 31, 2011. This difference is being accreted over 20 years.

Frac Tech Holdings, LLC. Frac Tech Holdings, LLC, a private company based in Fort Worth, Texas, provides hydraulic fracturing and other services to oil and gas companies. In the Current Quarter, we recorded positive equity method adjustments of $38 million for our share of Frac Tech s income and recorded depreciation adjustments of $8 million for our cost in excess of equity. The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $200 million as of March 31, 2011. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles.

Chaparral Energy, Inc. Chaparral Energy, Inc., based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties. In the Current Quarter, we recorded negative equity method adjustments of $2 million for our share of Chaparral s net loss and depreciation adjustments of $1 million for our cost in excess of equity. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $58 million as of March 31, 2011. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate. We recently announced our intention to monetize our 20% interest in Chaparral Energy, Inc.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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(Unaudited)

Monetization of this investment is subject to changes in market conditions and other factors, and we may not complete the transaction in the expected time frame or at all.

Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE Amex: GST), based in Houston, Texas, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. During the Current Quarter, the common stock price of Gastar increased from $4.30 per share to $4.86 per share. Our investment in Gastar had a historical cost basis of $89 million as of March 31, 2011.

10. Fair Value Measurements

Certain financial instruments are reported at fair value on the condensed consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

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

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of obligations under our deferred compensation plan, is based on quoted market prices.

Derivatives. The fair values of our commodity derivatives, interest rate swaps and foreign currency swaps are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparties for reasonableness. Since commodity, interest rate and foreign currency swaps do not include optionality and therefore have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. For interest rate options and swaptions, we use the fair value estimates provided by our respective counterparties, which are classified as Level 3 inputs. These values are reviewed internally for reasonableness using future interest rate curves and time to maturity. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date this has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of related qualifying interest rate swaps, which are reported at Level 2.

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(Unaudited)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of March 31, 2011:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 849	$	$	$ 849
Investments	33			33
Other long-term assets	56			56
Long-term debt		(1,421)		(1,421)
Other long-term liabilities	(56)			(56)
Derivatives:				
Commodity assets		677	101	778
Commodity liabilities		(140)	(2,884)	(3,024)
Interest rate liabilities		(79)		(79)
Foreign currency liabilities		(7)		(7)
Total derivatives		451	(2,783)	(2,332)
Total	$ 882	$ (970)	$ (2,783)	$ (2,871)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2010:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 102	$	$	$ 102
Investments	29			29
Other long-term assets	52			52
Long-term debt			(1,371)	(1,371)
Other long-term liabilities	(52)			(52)

Derivatives:								
Commodity assets				1,364		105		1,469
Commodity liabilities				(59)		(2,059)		(2,118)
Interest rate liabilities						(69)		(69)
Foreign currency liabilities						(43)		(43)
Total derivatives				1,305		(2,066)		(761)
Total	$	131	$	1,305	$	(3,437)	$	(2,001)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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(Unaudited)

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during the Current Quarter and the Prior Quarter is presented below:

	Commodity	Derivatives Interest Rate	Foreign Currency	Debt
		($ in millions)		
Beginning Balance as of January 1, 2011	$ (1,954)	$ (69)	$ (43)	$ (1,371)
Total gains (losses):				
Included in earnings (realized)[a]	6			
Included in earnings or change in net assets (unrealized)[a]	(879)	16		
Included in other comprehensive income (loss)				
Total purchases, issuances, sales and settlements:				
Settlements	44	(1)		
Transfers in and out of Level 3[c]		54	43	1,371
Ending Balance as of March 31, 2011	$ (2,783)	$	$	$
Beginning Balance as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses):				
Included in earnings (realized)[a]	103	(2)		
Included in earnings or change in net assets (unrealized)[a]	(18)	35	(48)	40
Included in other comprehensive income (loss)	6		2	
Total purchases, issuances, sales and settlements:				
Purchases	53			
Issuances				(450)[b]
Sales	(78)	(1)		
Settlements	(60)	3		550[b]
Transfers in and out of Level 3				
Ending Balance as of March 31, 2010	$ (660)	$ (97)	$ (3)	$ (1,258)

(a) Amounts related to commodity derivatives are included in natural gas and oil sales, and amounts related to interest rate and foreign currency derivatives and debt are included in interest expense.

(b) Amount represents a(n) (increase)/decrease in debt recorded at fair value as a result of new or terminated interest rate swaps.

(c) The values related to interest rate and foreign currency swaps were transferred from Level 3 to Level 2 as a result of our ability to use data readily available in the public market to corroborate our estimated fair values.

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Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for 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 fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock primarily using quoted market prices. Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	March 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 9,910	$ 11,608	$ 12,631	$ 13,272
Convertible preferred stock	$ 3,065	$ 3,072	$ 3,065	$ 3,019

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Condensed Consolidating Financial Information

Chesapeake Energy Corporation 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 and contingent convertible senior notes listed in Note 6 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our midstream subsidiary, CMD, is not a guarantor and is subject to covenants in the midstream revolving bank credit facility referred to in Note 6 that restrict it from paying dividends or distributions or making loans to Chesapeake.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of March 31, 2011 and December 31, 2010 and for the three months ended March 31, 2011 and 2010. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF MARCH 31, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 785	$ 64	$	$ 849
Other	8	2,569	144	(26)	2,695
Total Current Assets	8	3,354	208	(26)	3,544
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting, net		25,191	4		25,195
Other property and equipment, net		3,334	1,180		4,514
Total Property and Equipment, Net		28,525	1,184		29,709
Other assets	189	656	702		1,547
Investments in subsidiaries and intercompany advances	1,157	276		(1,433)	
TOTAL ASSETS	$ 1,354	$ 32,811	$ 2,094	$ (1,459)	$ 34,800
CURRENT LIABILITIES:					
Current liabilities	$ 228	$ 4,249	$ 218	$ (26)	$ 4,669
Intercompany payable (receivable) from parent	(24,317)	22,756	1,446	115	

Total Current Liabilities	(24,089)	27,005	1,664	89	4,669
LONG-TERM LIABILITIES:					
Long-term debt, net	9,915				9,915
Deferred income tax liabilities	466	1,620	144	(115)	2,115
Other liabilities	67	3,029	10		3,106
Total Long-Term Liabilities	10,448	4,649	154	(115)	15,136
STOCKHOLDERS EQUITY:					
Total Stockholders Equity	14,995	1,157	276	(1,433)	14,995
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 1,354	$ 32,811	$ 2,094	$ (1,459)	$ 34,800

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 2	$ 100	$	$ 102
Other	7	3,065	123	(31)	3,164
Total Current Assets	7	3,067	223	(31)	3,266
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting, net		27,822	4		27,826
Other property and equipment, net		3,246	1,306		4,552
Total Property and Equipment, Net		31,068	1,310		32,378
Other assets	166	669	700		1,535
Investments in subsidiaries and intercompany advances	1,217	269		(1,486)	
TOTAL ASSETS	$ 1,390	$ 35,073	$ 2,233	$ (1,517)	$ 37,179
CURRENT LIABILITIES:					
Current liabilities	$ 302	$ 4,082	$ 137	$ (31)	$ 4,490
Intercompany payable (receivable) from parent	(23,664)	21,955	1,596	113	
Total Current Liabilities	(23,362)	26,037	1,733	82	4,490
LONG-TERM LIABILITIES:					
Long-term debt, net	8,934	3,612	94		12,640
Deferred income tax liabilities	482	1,885	130	(113)	2,384
Other liabilities	72	2,322	7		2,401
Total Long-Term Liabilities	9,488	7,819	231	(113)	17,425
STOCKHOLDERS EQUITY:					

Total Stockholders Equity		15,264		1,217		269		(1,486)		15,264
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	1,390	$	35,073	$	2,233	$	(1,517)	$	37,179

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 494	$	$	$ 494
Marketing, gathering and compression sales		991	55	(29)	1,017
Service operations revenue		101			101
Total Revenues		1,586	55	(29)	1,612
OPERATING COSTS:					
Production expenses		238			238
Production taxes		45			45
General and administrative expenses		121	9		130
Marketing, gathering and compression expenses		968	39	(22)	985
Service operations expense		77			77
Natural gas and oil depreciation, depletion and amortization		358			358
Depreciation and amortization of other assets		56	12		68
(Gains) losses on sales of other property and equipment		2	(7)		(5)
Total Operating Costs		1,865	53	(22)	1,896
INCOME (LOSS) FROM OPERATIONS		(279)	2	(7)	(284)
OTHER INCOME (EXPENSE):					
Interest expense	(183)	(1)		177	(7)
Earnings from equity investees		6	19		25
Losses on redemptions or exchanges of debt	(2)				(2)
Other income	177	1	1	(177)	2
Equity in net earnings of subsidiary	(157)	9		148	
Total Other Income (Expense)	(165)	15	20	148	18
INCOME (LOSS) BEFORE INCOME TAXES	(165)	(264)	22	141	(266)
INCOME TAX EXPENSE (BENEFIT)	(3)	(107)	9	(3)	(104)
NET INCOME (LOSS)	$ (162)	$ (157)	$ 13	$ 144	$ (162)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,898	$	$	$ 1,898
Marketing, gathering and compression sales		813	48	(17)	844
Service operations revenue		56			56
Total Revenues		2,767	48	(17)	2,798
OPERATING COSTS:					
Production expenses		207			207
Production taxes		48			48
General and administrative expenses		104	5		109
Marketing, gathering and compression expenses		793	22		815
Service operations expense		49			49
Natural gas and oil depreciation, depletion and amortization		308			308
Depreciation and amortization of other assets		40	10		50
(Gains) losses on sales of other property and equipment					
Total Operating Costs		1,549	37		1,586
INCOME (LOSS) FROM OPERATIONS		1,218	11	(17)	1,212
OTHER INCOME (EXPENSE):					
Interest expense	(159)	(57)	(1)	192	(25)
Earnings (losses) from equity investees		(8)	21		13
Losses on redemptions or exchanges of debt	(2)				(2)
Other income	192	2		(192)	2
Equity in net earnings of subsidiary	719	9		(728)	
Total Other Income (Expense)	750	(54)	20	(728)	(12)
INCOME (LOSS) BEFORE INCOME TAXES	750	1,164	31	(745)	1,200
INCOME TAX EXPENSE (BENEFIT)	12	445	12	(7)	462
NET INCOME (LOSS)	$ 738	$ 719	$ 19	$ (738)	$ 738

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

THREE MONTHS ENDED MARCH 31, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 905	$ 61	$ (225)	$ 741
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(2,973)			(2,973)
Proceeds from divestitures of proved and unproved properties		5,182			5,182
Additions to other property and equipment		(180)	(251)		(431)
Other investing activities		(8)	373	60	425
Cash provided by (used in) investing activities		2,021	122	60	2,203
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		3,202	415		3,617
Payments on credit facilities borrowings		(6,814)	(509)		(7,323)
Proceeds from issuance of senior notes, net of offering costs	977				977
Cash paid to redeem debt	(128)				(128)
Other financing activities	(120)	760	(145)	165	660
Intercompany advances, net	(729)	709	20		
Cash provided by (used in) financing activities		(2,143)	(219)	165	(2,197)
Net increase (decrease) in cash and cash equivalents		783	(36)		747
Cash and cash equivalents, beginning of period		2	100		102
Cash and cash equivalents, end of period	$	$ 785	$ 64	$	$ 849

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

THREE MONTHS ENDED MARCH 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 1,123	$ 60	$	$ 1,183
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(2,050)			(2,050)
Proceeds from divestitures of proved and unproved properties		1,224			1,224
Additions to other property and equipment		(123)	(156)		(279)
Other investing activities		39	52		91
Cash provided by (used in) investing activities		(910)	(104)		(1,014)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		2,817	107		2,924
Payments on credit facilities borrowings		(2,874)	(70)		(2,944)
Other financing activities	(78)	136	2		60
Intercompany advances, net	78	(69)	(9)		
Cash provided by (used in) financing activities		10	30		40
Net increase (decrease) in cash and cash equivalents		223	(14)		209
Cash and cash equivalents, beginning of period		293	14		307
Cash and cash equivalents, end of period	$	$ 516	$	$	$ 516

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Recently Issued and Proposed Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued guidance requiring additional disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method effective beginning on January 1, 2011. We adopted this guidance in the Current Quarter. Adoption had no impact on our financial position or results of operations. See Note 10 for discussion regarding fair value measurements.

13. Subsequent Events

On April 14, 2011, we entered into an agreement and plan of merger to acquire, and have commenced a cash tender offer to purchase, all of the outstanding shares of Bronco Drilling Company, Inc. (NASDAQ: BRNC) for $11.00 a share. The cash tender offer will expire on May 23, 2011, unless extended. If the offer is successful, Chesapeake, through an indirect wholly owned subsidiary, will acquire any remaining Bronco shares in a later merger for $11.00 per share in cash. We anticipate that we will need approximately $315 million to purchase Bronco shares acquired in the tender offer, to pay the merger consideration for remaining Bronco shares not acquired in the cash tender offer, including shares issuable under an outstanding stock purchase warrant, and to pay related fees and expenses. The acquisition includes 22 high-quality drilling rigs, primarily operating in the Williston and Anadarko Basins, and has support from Bronco s two largest shareholders, who collectively own 32% of Bronco s stock.

On May 2 and 3, 2011, we completed and settled tender offers to purchase the following senior notes and contingent convertible senior notes in order to reduce the amount of our outstanding indebtedness. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets.

	Amount Tendered ($ in millions)
7.625% senior notes due 2013	$ 36
6.25% euro-denominated senior notes due 2017[a]	363
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
2.75% contingent convertible senior notes due 2035	55
2.5% contingent convertible senior notes due 2037	210
2.25% contingent convertible senior notes due 2038	266
	$ 1,287

(a) We purchased 256 million of our euro-denominated senior notes which had a value of $363 million as of March 31, 2011, based on the exchange rate of $1.4183 to 1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound foreign currency swaps for the same principal amount as the notes.

Also, we have offered to purchase $138 million of our 9.5% Senior Notes due 2015 and $439 million of our 6.5% Senior Notes due 2017 pursuant to tender offers which will expire on May 13, 2011.

Associated with the completed and pending tender offers described above, we expect to record a loss of approximately $185 million in the second quarter of 2011.

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Through a recently disclosed recapitalization of Frac Tech Holdings, LLC, on May 6, 2011, we received a cash distribution of approximately $200 million and now own 30% of the equity of a newly formed holding company of Frac Tech, Frac Tech International, LLC, up from our approximately 26% ownership prior to the recapitalization. In connection with the recapitalization, we have entered into a Master Frac Services Agreement that obligates us to use certain Frac Tech services through 2014, which services will be provided on market terms and at market rates.

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

Overview

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the three months ended March 31, 2011 (the Current Quarter) and the three months ended March 31, 2010 (the Prior Quarter):

	Three Months Ended March 31, 2011	2010
Net Production:		
Natural gas (bcf)	243.3	209.6
Oil (mmbbl)[(a)]	6.0	3.9
Natural gas equivalent (bcfe)[(b)]	279.6	232.8
Natural Gas and Oil Sales ($ in millions):		
Natural gas sales	$ 788	$ 942
Natural gas derivatives realized gains (losses)	505	379
Natural gas derivatives unrealized gains (losses)	(549)	415
Total natural gas sales	744	1,736
Oil sales[(a)]	400	242
Oil derivatives realized gains (losses)	(17)	20
Oil derivatives unrealized gains (losses)	(633)	(100)
Total oil sales	(250)	162
Total natural gas and oil sales	$ 494	$ 1,898
Average Sales Price (excluding all gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 3.24	$ 4.50
Oil ($ per bbl)[(a)]	$ 66.08	$ 62.59
Natural gas equivalent ($ per mcfe)	$ 4.25	$ 5.09
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 5.31	$ 6.31
Oil ($ per bbl)[(a)]	$ 63.20	$ 67.70
Natural gas equivalent ($ per mcfe)	$ 5.99	$ 6.80
Other Operating Income[(c)] ($ in millions):		
Marketing, gathering and compression net margin	$ 32	$ 29
Service operations net margin	$ 24	$ 7
Other Operating Income[(c)] ($ per mcfe):		
Marketing, gathering and compression net margin	$ 0.11	$ 0.12
Service operations net margin	$ 0.09	$ 0.03
Expenses ($ per mcfe):		
Production expenses	$ 0.85	$ 0.89
Production taxes	$ 0.16	$ 0.21
General and administrative expenses	$ 0.46	$ 0.47
Natural gas and oil depreciation, depletion and amortization	$ 1.28	$ 1.32
Depreciation and amortization of other assets	$ 0.24	$ 0.21

Interest expense[d]	$	0.00	$	0.22
Interest Expense ($ in millions):				
Interest expense[d]	$	8	$	55
Interest rate derivatives realized (gains) losses		(7)		(3)
Interest rate derivatives unrealized (gains) losses		6		(27)
Total interest expense	$	7	$	25
Net Wells Drilled		294		243
Net Producing Wells as of the End of the Period		22,141		22,669

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(a) Includes natural gas liquids (NGLs).

(b) Natural gas equivalent is based on six mcf of natural gas to one barrel of oil. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent commodity prices, the price for an mcfe of natural gas is significantly less than the price for an mcfe of oil or NGLs.

(c) Includes revenue and operating costs and excludes depreciation and amortization of other assets.

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

We are the second-largest producer of natural gas and a top 15 producer of oil and natural gas liquids in the U.S. We own interests in approximately 45,100 producing natural gas and oil wells that are currently producing approximately 3.0 bcfe per day, net to our interest, 85% of which is natural gas. The company has built a large resource base of onshore U.S. natural gas assets in the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in northwestern Louisiana and East Texas, the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania and the Pearsall Shale in South Texas. In the past few years, we have also built a substantial resource base of onshore U.S. liquids-rich assets in the Eagle Ford Shale in South Texas, the Granite Wash, Cleveland, Tonkawa and Mississippian plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle, the Niobrara Shale, Frontier and Codell plays in the Powder River and DJ Basins of Wyoming and Colorado, the Avalon, Bone Spring, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins of West Texas and southern New Mexico, the Three Forks/Bakken in the Williston Basin and the Utica Shale of the Appalachian Basin. We have also vertically integrated many of our operations and own substantial midstream, compression, drilling and oilfield service assets.

Chesapeake began 2011 with estimated proved reserves of 17.096 tcfe and ended the Current Quarter with 15.598 tcfe, a decrease of 1.498 tcfe, or 9%. On March 31, 2011, Chesapeake closed the sale of its upstream and midstream assets in the Fayetteville Shale, as described below under *Implementing our Strategy*. The sale included approximately 2.4 tcfe of proved reserves. Excluding this sale, Chesapeake s proved reserves would have been approximately 18.0 tcfe at March 31, 2011, an increase of 0.9 tcfe, or 5%, over the 2010 year-end proved reserves. The Current Quarter s proved reserve movement included 279.6 bcfe of production, 1,012 bcfe of extensions, 322 bcfe of positive performance revisions and 33 bcfe of downward revisions resulting from a decrease in the twelve-month trailing average natural gas prices between December 31, 2010 and March 31, 2011. During the Current Quarter, we acquired 17 bcfe of estimated proved reserves and divested 2.536 tcfe of estimated proved reserves.

During the Current Quarter, Chesapeake continued the industry s most active drilling program, drilling 375 gross (234 net) operated wells and participated in another 430 gross (60 net) wells operated by other companies. The company s drilling success rate was 98% for company-operated wells and 99% for non-operated wells. Also during the Current Quarter, we invested $1.314 billion in operated wells (using an average of 156 operated rigs) and $350 million in non-operated wells (using an average of 140 non-operated rigs) for total drilling, completing and equipping costs of $1.664 billion, net of drilling and completion carries of $527 million.

Our total Current Quarter production of 279.6 bcfe consisted of 243.3 bcf of natural gas (87% on a natural gas equivalent basis) and 6.0 mmbbls of oil and natural gas liquids (13% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 3.107 bcfe, an increase of 521 mmcfe, or 20%, over the 2.586 bcfe produced per day in the Prior Quarter.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (14.3 million net acres) and 3-D seismic (28.3 million acres) in the U.S. The company has accumulated the largest inventory of U.S. natural gas shale play leasehold (2.5 million net acres) and now owns leading positions in 12 of the Top 13 unconventional liquids-rich plays in the U.S. the Granite Wash, Cleveland, Tonkawa and Mississippian plays of the Anadarko Basin; the Avalon, Bone Spring, Wolfcamp and Wolfberry plays of the Permian Basin; the Eagle Ford Shale of South Texas; the Niobrara Shale in the Powder River and DJ Basins; the Three Forks/Bakken in the Williston Basin and the Utica Shale of the Appalachian Basin. We are currently using 156 operated drilling rigs to further develop our inventory of approximately 39,000 net drillsites.

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Implementing Our Strategy

In recognition of the value gap between oil and natural gas prices, since 2009 Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple unconventional liquids-rich plays on approximately 5.1 million net leasehold acres. Our production of oil and natural gas liquids averaged 67,200 bbls per day during the Current Quarter, a 56% increase over the average for the Prior Quarter as a result of the increased development of our unconventional liquids-rich plays. We are projecting that the portion of our drilling and completion capital expenditures allocated to liquids development will reach 50% in 2011 and 75% in 2012, and we expect to increase our oil and natural gas liquids production through our drilling activities to more than 150,000 bbls per day, or 20%-25% of total production, by year-end 2012.

This shift to a greater emphasis on liquids production is a continuation of our general business strategy. Our goal is to create value for investors by focusing on developing unconventional resource plays onshore in the U.S. We do so by growing through the drillbit, controlling substantial land and drilling location inventories and building regional scale, developing proprietary technological advantages, focusing on low costs through our operating scale and vertical integration, mitigating natural gas and oil price risk through our hedging program and with joint venture agreements.

Our strategic and financial plan for 2011-2012, announced on January 6, 2011 as our 25/25 Plan , outlines a 25% reduction in our outstanding long-term debt while growing net natural gas and oil production by 25% during these two years. We expect to achieve the reduction in debt primarily with proceeds from asset monetizations and from substantially reduced leasehold spending during this period. Among the several benefits of lower debt are lower borrowing costs, and we believe improved credit metrics will lead to a more favorable debt rating by the major ratings agencies. On April 8, 2011, Standard and Poor s upgraded our senior unsecured long-term debt rating to BB+. Steps that we have taken to achieve our strategic and financial plan are described below.

Fayetteville Shale Asset Monetization. On March 31, 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited, for net proceeds of approximately $4.65 billion in cash. The sold properties consisted of approximately 487,000 net acres of leasehold, current net production of approximately 415 mcfe per day and midstream assets consisting of approximately 420 miles of pipeline. As part of the transaction, we have agreed to provide technical and business services for up to one year for BHP Billiton s Fayetteville properties for an agreed-upon fee. Pending the consummation of the tender offers described below, we used a portion of the funds we received from the Fayetteville transaction to temporarily repay all borrowings outstanding under our corporate revolving bank facility.

Repurchases of Senior Debt. On May 2 and 3, 2011, we completed tender offers to purchase $756 million of certain of our senior notes and $531 million of certain of our contingent convertible senior notes. We have also offered to purchase an additional $577 million of senior notes pursuant to tender offers which will expire on May 13, 2011. These tender offers are part of our 25/25 Plan to reduce the amount of our outstanding indebtedness. We funded the purchase of the notes with a portion of the net proceeds we received from the monetization of our Fayetteville Shale assets. Combined with the $140 million of contingent convertible senior notes we purchased in privately negotiated transactions during the Current Quarter, upon completion of the pending tender offers, we will have retired an aggregate principal amount of $2.004 billion of senior notes and contingent convertible senior notes in 2011.

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Joint Ventures. On February 11, 2011, we entered into a joint venture with a wholly owned subsidiary of CNOOC Limited (CNOOC) to sell a 33.3% undivided interest in approximately 800,000 net acres of leasehold overlaying the Niobrara Shale, Codell and various other formations in the Powder River and DJ Basins in northeast Colorado and southeast Wyoming. Under the terms of the joint venture, we received $570 million in cash at closing, and CNOOC has agreed to fund 66.7% of our share of drilling and completion costs until an additional $697 million has been paid, which we expect to occur by year-end 2014. CNOOC also has the right to a 33.3% participation in any additional leasehold we acquire in the area at cost plus a fee. Proceeds from this transaction are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

The following table provides information about the drilling and completion carries that remain available to us from our joint venture partners as of March 31, 2011:

Primary Play	Joint Venture Partner	Date	Carries Remaining ($ in millions)
Marcellus	Statoil	November 2008	$ 1,118
Barnett	Total	January 2010	752
Eagle Ford	CNOOC	November 2010	908
Niobrara	CNOOC	February 2011	673
			$ 3,451

The drilling and completion carries in our joint venture agreements create a significant cost advantage that allows us to reduce our finding costs. During the Current Quarter and the Prior Quarter, our drilling and completion costs included the benefit of approximately $527 million and $281 million, respectively, of drilling and completion carries. Our drilling and completion costs for 2011 through 2014 will continue to be partially offset by the use of our remaining drilling and completion carries associated with our joint venture agreements.

During the Current Quarter, as part of our joint venture agreements with CNOOC, Total, Statoil and Plains Exploration & Production Company, we sold interests in additional leasehold in the Eagle Ford, Barnett, Marcellus and Haynesville and Bossier Shale plays for proceeds of approximately $224 million that had an estimated original cost to us of $164 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Volumetric Production Payment (VPP). We have agreed to monetize certain of our producing assets in the Mid-Continent through a ten-year VPP for proceeds of approximately $850 million. The transaction includes approximately 180 bcfe of proved reserves and approximately 80 mmcfe per day of current net production. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and we also retain all production beyond the specified volumes sold in the transaction. The transaction will be our ninth VPP and it is expected to close in the second quarter of 2011. The cash proceeds for this transaction will be reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Planned Asset Monetizations. During 2011 and 2012, the company expects to enter into additional asset monetizations, including joint ventures, production monetizations (such as VPPs and/or royalty trusts), certain midstream asset sales, the monetization of some or all of our equity interests in Chaparral Energy, Inc. and Frac Tech International, LLC, and various other smaller planned sales. Each of these monetizations is subject to changes in market conditions and other factors, and we may not complete any such transactions in the expected time frame or at all.

Oilfield Service Vertical Integration Strategy. We have built a large inventory of low-risk natural gas and liquids resources which we plan to develop aggressively in the decades ahead. As a result, we will consistently utilize a large and growing amount of oilfield services for this resource development. In the next decade alone, our gross drilling and completion expenditures may reach $100 billion. This high level of planned drilling activity will create considerable value for the providers of oilfield services, and our strategy is to capture a portion of this value for our shareholders rather than transfer it to third-party vendors. In addition, we utilize our service company operations as a hedge against oilfield service inflation.

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To date, we have invested in drilling rigs, compression equipment, rental tools, water management equipment, trucking, midstream services and most recently, fracture stimulation equipment. Our industry-leading drilling and completion activities require a high level of planning and project coordination that we believe is best accomplished through vertical integration and ownership of a significant portion of the oilfield services we utilize. This vertical integration approach also creates a multitude of cost savings, an alignment of interests, operational synergies, greater capacity of equipment, increased safety and better coordinated logistics. In addition, our control of a large portion of the oilfield service equipment we utilize provides unique advantages in accelerating the timing of our leasehold development and therefore accelerating the creation of present value from our vast inventory of undeveloped properties.

As an extension of our vertical integration strategy, on April 14, 2011, we entered into an agreement and plan of merger to acquire, and have commenced a cash tender offer to purchase, all of the outstanding shares of Bronco Drilling Company, Inc. (NASDAQ: BRNC) for $11.00 a share. The cash tender offer will expire on May 23, 2011, unless extended. If the offer is successful, Chesapeake, through an indirect wholly owned subsidiary, will acquire any remaining Bronco shares in a later merger for $11.00 per share in cash. We anticipate that we will need approximately $315 million to purchase Bronco shares acquired in the tender offer, to pay the merger consideration for remaining Bronco shares not acquired in the cash tender offer, including shares issuable under an outstanding stock purchase warrant, and to pay related fees and expenses. The acquisition includes 22 high-quality drilling rigs primarily operating in the Williston and Anadarko Basins and has support from Bronco s two largest shareholders, who collectively own 32% of Bronco s stock.

Through a recently disclosed recapitalization of Frac Tech Holdings, LLC, on May 6, 2011 we received a cash distribution of approximately $200 million and now own 30% of the equity of a newly formed holding company of Frac Tech, Frac Tech International, LLC, up from our approximately 26% ownership prior to the recapitalization. In connection with the recapitalization, we have entered into a Master Frac Services Agreement that obligates us to use certain Frac Tech services through 2014, which services will be provided on market terms and at market rates.

Capital Expenditures

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Our current budgeted drilling and completion capital expenditures, net of drilling and completion carries, are $5.5 - $6.0 billion in each of 2011 and 2012. We anticipate funding substantially all budgeted drilling and completion capital expenditures using cash flow from operations in 2011 and 2012. We plan to fund our leasehold acquisition capital expenditures, together with other capital expenditure requirements, with a combination of revolving bank credit facility borrowings and proceeds from asset monetizations. As of March 31, 2011, we had made commitments to acquire additional proved and unproved properties in various transactions during the next twelve months for approximately $400 million.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $741 million in the Current Quarter compared to $1.183 billion in the Prior Quarter. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, deferred income taxes and changes in our derivative instruments. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. To mitigate the risk of declines in natural gas and oil prices and to provide more predictable future cash flow from operations, we have entered into various derivative instruments. Assuming future NYMEX natural gas settlement prices average $4.50 per mcf and NYMEX oil settlement prices average $100 per bbl for 2011, and including the effect of the company s open derivatives, closed contracts and previously collected call premiums, as of May 2, 2011, the company estimates its average natural gas price will be $5.98 per mcf and average oil price will be $96.22 per bbl for 2011. This estimate does not include the effect of gathering costs and basis differentials, which include the effect of lower priced NGLs on our reported realized prices. Our natural gas and oil derivatives as of March 31, 2011 are detailed in Item 3 of

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Part I of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows. In the Current Quarter and Prior Quarter, we received $660 million and $94 million, respectively, for settlements of derivatives which were classified as cash flows from financing activities.

Joint ventures and asset monetizations are part of our business strategy to fund our leasehold acquisition spending and our planned reduction in long-term indebtedness. Current Quarter property divestiture proceeds of $5.182 billion included $4.310 billion from the sale of our Fayetteville assets, $570 million at the closing of our Niobrara Shale joint venture and $302 million from other property sales. Prior Quarter property divestiture proceeds of $1.224 billion included $800 million in cash at the closing of our Barnett Shale joint venture, $244 million from property sales pursuant to our joint venture agreement with Statoil and $180 million from our sixth VPP transaction. The Fayetteville sale in the Current Quarter also included proceeds of $352 million for other property and equipment.

Our $4.0 billion corporate revolving bank credit facility, our $300 million midstream revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use the credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $3.617 billion and repaid $7.323 billion in the Current Quarter, and we borrowed $2.924 billion and repaid $2.944 billion in the Prior Quarter from our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our midstream facility is secured by substantially all of our wholly owned midstream assets and is not subject to periodic borrowing base redeterminations. Our revolving bank credit facilities are described below under *Bank Credit Facilities*.

During the Current Quarter, in an effort to extend the maturity profile of our outstanding indebtedness at advantageous rates, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our revolving bank credit facility.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities and our other investing activities for the Current Quarter and the Prior Quarter. 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, changes in 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.

During the Current Quarter, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $129 million, including accrued interest. Associated with these repurchases, we recognized a loss of $2 million in the Current Quarter.

We paid dividends on our common stock of $48 million and $47 million in the Current Quarter and the Prior Quarter, respectively. We paid dividends on our preferred stock of $43 million in the Current Quarter and $6 million in the Prior Quarter.

Credit Risk

Derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. On March 31, 2011, our commodity and interest rate derivative instruments were spread among 13 counterparties. Our multi-counterparty secured hedging facility includes 12 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($917 million at March 31, 2011) and exploration and production companies which own interests in properties we operate ($1.183 billion at March 31, 2011). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter and the Prior Quarter, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash provided by (used in) investing activities increased to $2.203 billion during the Current Quarter, compared to ($1.014) billion during the Prior Quarter. The majority of the $3.217 billion increase in cash provided by investing activities was the result of the sale of our Fayetteville Shale assets. We made significant additions to our liquids-rich leasehold acreage in both the Current Quarter and the Prior Quarter, with acquisitions of unproved properties totaling $1.065 billion and $867 million, respectively. We are projecting substantially reduced leasehold acquisition activity in the remainder of 2011 and in 2012. Exploration and development expenditures increased $642 million to $1.621 billion in the Current Quarter compared to $979 million in the Prior Quarter. This increase is due to increased drilling activity. The following table shows our cash provided by (used in) investing activities during these periods:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Acquisitions of proved properties	$ (18)	$ (8)
Acquisitions of unproved properties	(1,065)	(867)
Exploration and development of natural gas and oil properties	(1,621)	(979)
Geological and geophysical costs[(a)]	(71)	(41)
Interest capitalized on unproved properties	(198)	(155)
Proceeds from divestitures of proved and unproved properties	5,182	1,224
Total natural gas and oil investing activities	2,209	(826)
Other Investing Activities:		
Additions to other property and equipment	(431)	(279)
Proceeds from sales of other assets	428	56
Other	(3)	35
Total other investing activities	(6)	(188)
Total cash provided by (used in) investing activities	$ 2,203	$ (1,014)

(a) Including related capitalized interest.

Bank Credit Facilities

We utilize two bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility[a]	Midstream Credit Facility[b]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	July 2015
Borrowing capacity	$ 4,000	$ 300
Amount outstanding as of March 31, 2011	$	$
Letters of credit outstanding as of March 31, 2011	$ 13	$

(a) Borrower is Chesapeake Exploration, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C., a wholly owned subsidiary of Chesapeake Midstream Development, L.P.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities contains 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.

Corporate Credit Facility

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A., or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at March 31, 2011. 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 $50 million or more, 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 of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries.

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Midstream Credit Facility

Our $300 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.75% to 2.25% per annum according to the most recent leverage ratio described below or (ii) the Eurodollar rate, which is based on the LIBOR plus a margin that varies from 2.75% to 3.25% per annum according to the most recent leverage ratio. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted subsidiaries to incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our master limited partnership midstream affiliate, Chesapeake Midstream Partners, L.P. As of December 21, 2010, the leverage ratio increased for a three-fiscal-quarter period beginning October 1, 2010 due to the sale of the Springridge gathering system, as it was classified as a material disposition of assets. We were in compliance with all covenants under the agreement at March 31, 2011. If CMD or its restricted subsidiaries should fail to perform their 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. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

Hedging Facility

We have a multi-counterparty secured hedging facility with 12 counterparties that have committed to provide approximately 5.6 tcfe of trading capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. In February 2011, we amended the agreement for the hedge facility primarily to allow us to protect our natural gas liquids production from price volatility and to allow for greater flexibility when hedging our anticipated production. As of March 31, 2011, we had hedged a total of 2.9 tcfe of our future production under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas, oil and natural gas liquids hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into hedges with the company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

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Senior Note Obligations

As of March 31, 2011, senior notes represented approximately $9.9 billion of our total debt and consisted of the following ($ in millions):

7.625% senior notes due 2013	$	500
9.5% senior notes due 2015		1,425
6.25% euro-denominated senior notes due 2017[a]		851
6.5% senior notes due 2017		1,100
6.875% senior notes due 2018		600
7.25% senior notes due 2018		800
6.625% senior notes due 2020		1,400
6.875% senior notes due 2020		500
6.125% senior notes due 2021		1,000
2.75% contingent convertible senior notes due 2035[b]		451
2.5% contingent convertible senior notes due 2037[b]		1,378
2.25% contingent convertible senior notes due 2038[b]		612
Discount on senior notes[c]		(707)
Interest rate derivatives[d]		5
	$	9,915

(a) The principal amount shown is based on the exchange rate of $1.4183 to 1.00 as of March 31, 2011. See Note 2 of our condensed consolidated financial statements included in this report for information on our related foreign currency derivatives.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the first quarter of 2011, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2011 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period in which contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.62	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.26	November 14, 2017

2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Included in this discount is $645 million at March 31, 2011 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(d) See Note 2 of our condensed consolidated financial statements included in this report for discussion related to these instruments.

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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 to all of our future subordinated indebtedness. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries. See Note 11 of the condensed consolidated financial statements included in this report for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Our senior notes are governed by indentures containing covenants that limit our ability and our subsidiaries ability to incur certain secured indebtedness; enter into sale/leaseback transactions; and consolidate, merge or transfer assets.

On May 2 and 3, 2011, we completed and settled tender offers to purchase the following senior notes and contingent convertible senior notes in order to reduce the amount of our outstanding indebtedness. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets.

	Amount Tendered ($ in millions)
7.625% senior notes due 2013	$ 36
6.25% euro-denominated senior notes due 2017[a]	363
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
2.75% contingent convertible senior notes due 2035	55
2.5% contingent convertible senior notes due 2037	210
2.25% contingent convertible senior notes due 2038	266
	$ 1,287

(a) We purchased 256 million of our euro-denominated senior notes which had a value of $363 million as of March 31, 2011, based on the exchange rate of $1.4183 to 1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound foreign currency swaps for the same principal amount as the notes.

Also, we have offered to purchase $138 million of our 9.5% Senior Notes due 2015 and $439 million of our 6.5% Senior Notes due 2017 pursuant to tender offers which will expire on May 13, 2011.

Associated with the completed and pending tender offers described above, we expect to record a loss of approximately $185 million in the second quarter of 2011.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at March 31, 2011. These include commitments related to drilling rig and compressor leases, transportation and drilling contracts, natural gas and oil purchase obligations, minimum volume commitments, net acreage maintenance commitments and leasehold purchase commitments. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in this report.

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Results of Operations Three Months Ended March 31, 2011 vs. March 31, 2010

General. For the Current Quarter, Chesapeake had a net loss of $162 million, or $0.32 per diluted common share, on total revenues of $1.612 billion. This compares to net income of $738 million, or $1.14 per diluted common share, on total revenues of $2.798 billion during the Prior Quarter. The Current Quarter loss was due to a net unrealized after-tax mark-to-market loss of $725 million resulting from our natural gas, oil and interest rate hedging programs.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $494 million compared to $1.898 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 279.6 bcfe at a weighted average price of $5.99 per mcfe, compared to 232.8 bcfe produced in the Prior Quarter at a weighted average price of $6.80 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($1.182) billion and $315 million in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $227 million and increased production resulted in a $319 million increase, for a total increase in revenues of $92 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Quarter to the Current Quarter was generated through the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $5.31, compared to $6.31 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Included in the Current Quarter realized price of natural gas are gains related to swaps that had an above-market fixed price on the origination date. We obtained these above-market swaps by selling out-year call options on a portion of our projected natural gas and oil production. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of March 31, 2011. Oil prices realized per barrel (excluding unrealized gains or (losses) on derivatives) were $63.20 and $67.70 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $488 million, or $1.74 per mcfe, in the Current Quarter and a net increase of $399 million, or $1.71 per mcfe, in the Prior Quarter.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Quarter production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $24 million and an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $6 million without considering the effect of hedging activities.

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The following tables show our production and prices received by region for the Current Quarter and the Prior Quarter:

	Three Months Ended March 31, 2011						
	Natural Gas		Oil[(a)]		Total		
	(bcf)	($/mcf)[(b)]	(mmbbl)	($/bbl)[(b)]	(bcfe)	%	($/mcfe)[(b)]
Haynesville/Bossier Shales	85.3	3.32			85.3	30%	3.32
Mid-Continent	55.6	3.93	4.5	63.54	82.6	29	6.09
Fayetteville Shale	35.9	2.82			35.9	13	2.82
Barnett Shale	23.9	1.14	0.2	34.00	25.2	9	1.37
Marcellus Shale	22.8	3.75	0.2	57.61	24.0	9	4.03
Permian and Delaware Basins	8.1	4.03	0.8	83.57	13.0	5	7.79
Eagle Ford Shale	0.8	7.18	0.2	86.83	2.0	1	11.31
Rockies/Williston Basin	0.2	4.16			0.2		4.16
Other	10.7	3.00	0.1	72.76	11.4	4	3.67
Total[(c)]	243.3	3.24	6.0	66.08	279.6	100%	4.25

	Three Months Ended March 31, 2010						
	Natural Gas		Oil[(a)]		Total		
	(bcf)	($/mcf)[(b)]	(mmbbl)	($/bbl)[(b)]	(bcfe)	%	($/mcfe)[(b)]
Haynesville/Bossier Shales	40.7	4.44			40.7	18%	4.44
Mid-Continent	55.5	5.35	2.9	59.69	72.7	31	6.44
Fayetteville Shale	31.1	3.97			31.1	13	3.97
Barnett Shale	49.6	3.51	0.1	38.44	50.2	21	3.55
Marcellus Shale	7.5	5.20			7.5	3	5.20
Permian and Delaware Basins	12.3	5.21	0.7	75.65	16.5	7	7.12
Eagle Ford Shale	0.1	3.62			0.1		3.62
Rockies/Williston Basin	0.1	4.21			0.1	1	4.21
Other	12.7	4.97	0.2	73.78	13.9	6	5.37
Total[(d)]	209.6	4.50	3.9	62.59	232.8	100%	5.09

(a) Includes NGLs.

(b) The average sales price excludes gains (losses) on derivatives.

(c) The Current Quarter production reflects the sale of a 25% joint venture interest in our Barnett Shale assets in January 2010 and various other asset sales, including VPP #6, VPP #7 and VPP #8.

(d) The Prior Quarter production reflects the sale of a 25% joint venture interest in our Barnett Shale assets in January 2010 and VPP #6.

Our average daily production of 3.107 bcfe for the Current Quarter consisted of 2.704 bcf of natural gas and 67,200 barrels of oil. Our Current Quarter production of 279.6 bcfe consisted of 243.3 bcf (87% on a natural gas equivalent basis) and 6.0 mmbbls (13% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 16% and our year-over-year growth rate of oil and NGL (liquids) production was 56%. Our percentage of revenue from liquids in the Current Quarter was 23% of realized natural gas and oil revenue compared to 17% in the Prior Quarter.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression sales and operating expenses consist of third-party revenue and operating expenses related to our midstream operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $1.017 billion in marketing, gathering and compression sales in the Current Quarter with corresponding marketing, gathering and compression expenses of $985 million, for a net margin before depreciation of $32 million. This compares to sales of $844 million, expenses of $815 million and a net margin before depreciation of $29 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in marketing, gathering and compression sales and operating expenses primarily due to an increase in third-party marketing, gathering and compression volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $101 million in service operations revenue in the Current Quarter with corresponding service operations expense of $77 million, for a net margin before depreciation of $24 million. This compares to revenue of $56 million, expenses of $49 million and a net margin before depreciation of $7 million in the Prior Quarter. Service operations margins have increased as service rates increased throughout 2010 and 2011. The economic slowdown toward the end of 2008 and throughout 2009 caused service rates to decrease and stacked rigs to increase, resulting in much lower operating margins toward the beginning of 2010.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $238 million in the Current Quarter and $207 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.85 per mcfe in the Current Quarter compared to $0.89 per mcfe in the Prior Quarter. The per unit expense decrease in the Current Quarter was primarily the result of completing new high volume wells with lower per unit production costs.

Production Taxes. Production taxes were $45 million in the Current Quarter compared to $48 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.16 per mcfe in the Current Quarter compared to $0.21 per mcfe in the Prior Quarter. The $3 million decrease in production taxes in the Current Quarter is due to a decrease in the average realized sales price of natural gas and oil of $0.84 per mcfe (excluding gains or losses on derivatives), which was partially offset by an increase in production of 46.8 bcfe. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties and other property, plant and equipment, were $130 million in the Current Quarter and $109 million in the Prior Quarter. The increase in the Current Quarter was the result of the company s continued growth resulting in higher payroll and associated costs. General and administrative expenses were $0.46 and $0.47 per mcfe for the Current Quarter and Prior Quarter, respectively. Included in general and administrative expenses is stock-based compensation of $23 million for the Current Quarter and $22 million for the Prior Quarter. Restricted stock expense is based on the price of our common stock on the grant date of the award.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. Employee restricted stock awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 5 of our condensed consolidated financial statements included in Item 1 of Part I of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. In addition, we capitalize internal costs that can be identified with the construction of certain of our property, plant and equipment. We capitalized $109 million and $102 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts and the construction of our property, plant and equipment.

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Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas and oil properties was $358 million and $308 million during the Current Quarter and the Prior Quarter, respectively. The $50 million increase is primarily the result of a 20% increase in production from the Prior Quarter compared to the Current Quarter. 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 $1.28 and $1.32 in the Current Quarter and in the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $68 million in the Current Quarter and $50 million in the Prior Quarter. Depreciation and amortization of other assets was $0.24 and $0.21 per mcfe for the Current Quarter and the Prior Quarter, respectively. The increase in the Current Quarter is primarily due to additional depreciation expense associated with assets acquired over the past year. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to twenty years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration and development costs.

Gains on Sales of Other Property and Equipment. In the Current Quarter, we recorded a $5 million net gain associated with the sales of other property and equipment, primarily in our Fayetteville Shale asset sale to BHP Billiton.

Interest Expense. Interest expense was $7 million in the Current Quarter compared to $25 million in the Prior Quarter as follows:

	Three Months Ended March 31,	
	2011	2010
	($ in millions)	
Interest expense on senior notes	$ 177	$ 192
Interest expense on credit facilities	21	12
Capitalized interest	(205)	(161)
Realized (gain) loss on interest rate derivatives	(7)	(3)
Unrealized (gain) loss on interest rate derivatives	6	(27)
Amortization of loan discount and other	15	12
Total interest expense	$ 7	$ 25
Average long-term borrowings	$ 10,196	$ 11,143

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was nominal per mcfe in the Current Quarter compared to $0.22 per mcfe in the Prior Quarter. The decrease in interest expense per mcfe is due primarily to increased production volumes, a decrease in our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased $44 million in the Current Quarter compared to the Prior Quarter as a result of a significant increase in unevaluated properties, the base on which interest is capitalized.

Earnings from Equity Investees. Earnings from equity investees were $25 million and $13 million in the Current Quarter and the Prior Quarter, respectively, primarily as result of our equity in the net income of certain investments.

Losses on Redemptions or Exchanges of Debt. In the Current Quarter, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $129 million, including accrued interest. Associated with these repurchases, we recognized a loss of $2 million in the Current Quarter.

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In the Prior Quarter, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. Associated with these exchanges, we recognized a loss of $2 million in the Prior Quarter.

Other Income. Other income was $2 million in both the Current Quarter and Prior Quarter. The Current Quarter and the Prior Quarter both consisted of $1 million of interest income and $1 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded an income tax benefit of $104 million in the Current Quarter compared to income tax expense of $462 million in the Prior Quarter. Of the $566 million decrease in income tax expense recorded in the Current Quarter, $565 million was the result of the decrease in net income before income taxes and $1 million was due to an increase in the effective tax rate. Our effective income tax rate was 39% in the Current Quarter and 38.5% in the Prior Quarter. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties and income taxes 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, 2010 (2010 Form 10-K).

Recently Issued and Proposed Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued guidance requiring additional disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method effective beginning on January 1, 2011. We adopted this guidance in the Current Quarter. Adoption had no impact on our financial position or results of operations. See Note 10 to our condensed consolidated financial statements in Item 1 of Part I of this report for a discussion regarding fair value measurements.

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, as amended (the Exchange Act). Forward-looking statements give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures, and anticipated asset acquisitions and sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures 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 2010 Form 10-K. They include:

- the volatility of natural gas and oil prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs;
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs;

our ability to replace reserves and sustain production;

uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures;

- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;
- leasehold terms expiring before production can be established;
- hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities;
- drilling and operating risks, including potential environmental liabilities;
- changes in legislation and regulation adversely affecting our industry and our business;
- general economic conditions negatively impacting us and our business counterparties;
- oilfield services shortages, pipeline and gathering system capacity constraints and transportation interruptions that could adversely affect our cash flow; 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 (SEC) that attempt to advise interested parties of the risks and factors that may affect our business.

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

Natural Gas and Oil Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for attempting to mitigate exposure to adverse natural gas and oil price changes is to hedge into strengthening natural gas and oil futures markets when prices allow us to generate high cash margins and when we view prices to be in the upper range of our predicted future price range. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas import trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps and options (puts or calls). All of these are described in more detail below. We typically use swaps for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes when the strike price levels and the premiums are attractive to us. Since late 2009, we have taken advantage of attractive strip prices in 2012 through 2017 and sold natural gas and oil call options to our counterparties in exchange for 2010, 2011 and 2012 natural gas swaps with fixed prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for natural gas swaps with fixed prices in excess of the market price for natural gas at that time. Additionally, we sell call options when we would be satisfied to sell our production at the price being capped by the call strike or believe it to be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive.

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We determine the volume we may potentially hedge by reviewing our estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production (risked) from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not hedge more volumes than we expect to produce, and if production estimates are lowered for future periods and hedges are already executed for some volume above the new production forecasts, the hedges are reversed. The actual fixed hedge price on our derivative instruments is derived from bidding and the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price payment, resulting in a net amount due to or from the counterparty.

We adjust our derivative positions in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our derivative positions continuously and if future market conditions change and prices have moved to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original derivative position. Gains or losses related to closed positions will be realized in the month of related production based on the terms specified in the original contract.

In the latter half of 2010, we restructured a portion of our call options by lowering the strike price on call options sold for 2012 through 2015 and used the value to buy back call options for the same periods. This increased our capacity to hedge additional volumes.

As of March 31, 2011, our natural gas and oil derivative instruments consisted of the following:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.

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 a certain pre-determined knockout price.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

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As of March 31, 2011, we had the following open natural gas and oil derivative instruments.

	Volume (bbtu)	Weighted Average Price Fixed	Put	Call (per mmbtu)	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Natural Gas:							
Qualified Swaps:							
Q2 2011	128,487	$ 5.23	$	$	$	Yes	$ 112
Q3 2011	177,100	4.90				Yes	60
Q4 2011	176,185	4.85				Yes	9
2012	31,000	6.15				Yes	35
2013 2021	96,517	5.86				Yes	(41)
Non-Qualified Swaps:							
Q2 2011	77,722	5.70				No	104
Q3 2011	22,400	7.00				No	55
Q4 2011	26,670	6.52				No	45
2012	174,960	6.21				No	208
Call Options:							
2012	161,077			6.54		No	(30)
2013	436,033			6.44		No	(180)
2014	330,183			6.43		No	(211)
2015	226,446			6.31		No	(201)
2016 2020	324,003			8.13		No	(300)
Put Options:							
Q2 2011	(9,100)		5.75			No	(12)
Q3 2011	(16,560)		5.42			No	(16)
Q4 2011	(16,560)		5.48			No	(16)
Basis Protection Swaps (Non-Appalachian Basin):							
Q2 2011	22,760				(0.72)	No	(12)
Q3 2011	22,867				(0.72)	No	(12)
Q4 2011	9,886				(0.59)	No	(4)
2012	62,819				(0.65)	No	(23)
2013 2021	96,981				(0.31)	No	(8)
Basis Protection Swaps (Appalachian Basin):							
Q2 2011	12,186				0.14	No	
Q3 2011	12,403				0.14	No	1
Q4 2011	12,324				0.14	No	1
2012 2022	134				0.11	No	
Total Natural Gas							(436)

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	Volume (mbbl)	Fixed	Weighted Average Price (per bbl) Put	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Oil:							
Qualified Swaps:							
Q2 2011	1,953	$ 102.89		$	$	Yes	$ (9)
Q3 2011	1,966	102.91				Yes	(10)
Q4 2011	1,961	102.92				Yes	(10)
2012	5,927	103.95				Yes	(14)
2013 2021	2,285	99.06				Yes	(7)
Call Options[a]:							
Q2 2011	2,275			72.81		No	(56)
Q3 2011	2,300			72.81		No	(60)
Q4 2011	2,300			72.81		No	(63)
2012	23,969			84.12		No	(567)
2013	14,564			87.20		No	(348)
2014	8,707			87.72		No	(203)
2015	7,411			85.31		No	(184)
2016 2017	10,600			84.25		No	(277)
Knock-Out Swaps:							
Q2 2011	273	104.75	60.00			No	(1)
Q3 2011	276	104.75	60.00			No	(1)
Q4 2011	276	104.75	60.00			No	(1)
2012	732	109.50	60.00			No	1
Total Oil							(1,810)
Total Natural Gas and Oil							$ (2,246)

(a) Included in oil call options are NGL call options in the amount of 5,000 bbls per day at $39.06 per bbl for 2011 and $38.01 per bbl for 2012. Also, included are options that allow the counterparty to enter into a 12-month oil swap for 5,000 bbls per day at $100 per bbl for each of 2012 and 2013.

In addition to the open derivative positions disclosed above, at March 31, 2011, we had $517 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas and oil sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below:

	March 31, 2011 ($ in millions)
Q2 2011	$ 256
Q3 2011	211
Q4 2011	187
2012	42
2013	18
2014	(237)
2015	51
2016 2022	(11)

Total	$	517

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We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is also considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been mitigated under our secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

The table below reconciles the Current Quarter change in fair value of our natural gas and oil derivatives. Of the $2.246 billion fair value liability as of March 31, 2011, $48 million related to contracts maturing in the next 12 months, of which we expect to transfer approximately ($35) million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($2.294) billion related to contracts maturing after 12 months. All transactions hedged as of March 31, 2011 are expected to mature by December 31, 2022.

	2011 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ (649)
Change in fair value of contracts	(753)
Contracts realized or otherwise settled	(320)
Fair value of contracts when closed	(524)
Fair value of contracts outstanding, as of March 31	$ (2,246)

The change in natural gas and oil prices during the Current Quarter increased the value of our derivative liabilities by $753 million. This loss is recorded in natural gas and oil sales or in accumulated other comprehensive income. We settled contracts for $320 million and we closed out contracts that were in an asset position for $524 million. The realized gain is recorded in natural gas and oil sales in the month of related production.

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following these provisions, 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 accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Realized gains (losses) consist of settled contracts related to the production periods being reported. Unrealized gains (losses) consist of both temporary fluctuations in the mark-to-market values of non-qualifying contracts and settled values of non-qualifying derivatives related to future production periods.

The components of natural gas and oil sales for the Current Quarter and the Prior Quarter are presented below.

	Three Months Ended March 31, 2011	2010
	($ in millions)	
Natural gas and oil sales	$ 1,188	$ 1,184
Realized gains (losses) on natural gas and oil derivatives	488	399
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(1,192)	321
Unrealized gains (losses) on ineffectiveness of cash flow hedges	10	(6)
Total natural gas and oil sales	$ 494	$ 1,898

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Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2011	2012	2013	2014	2015	Thereafter	Total
	($ in millions)						
Liabilities:							
Long-term debt fixed rate[(a)]	$	$	$ 500	$	$ 1,425	$ 8,692	$ 10,617
Average interest rate			7.63%		9.50%	5.44%	6.09%
Long-term debt variable rate	$	$	$	$	$	$	$
Average interest rate							

(a) This amount does not include the discount included in long-term debt of ($707) million and interest rate derivatives of $5 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 facilities. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of March 31, 2011, our interest rate derivative instruments consisted of the following types of instruments:

Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and a pay fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

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As of March 31, 2011, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Floating[a]	Fair Value Hedge	Net Premiums	Fair Value ($ in millions)
Fixed to Floating:						
Swaps						
Mature 2017 2020	$ 600	6.75%	3 mL plus 397 bp	Yes	$	$ (31)
Mature 2017 2020	$ 750	6.67%	3 mL plus 382 bp	No		(30)
Call Options						
Expire Q2 2011	$ 250	6.88%	3 mL plus 351 bp	No	7	
Swaption						
Expire Q2 2011	$ 100	6.63%	3 mL plus 254 bp	No	1	
Floating to Fixed:						
Swaps						
Mature 2014	$ 1,050	2.19%	1 6 mL	No		(18)
					$ 8	$ (79)

(a) Month LIBOR has been abbreviated mL and basis points has been abbreviated bp .

In addition to the open derivative positions disclosed above, at March 31, 2011 we had $92 million of net hedging gains related to settled contracts that will be recorded within interest expense as realized gains (losses) as they are transferred from either our senior note liability or unrealized interest expense gains (losses) over the next ten-year term of the related senior notes. In conjunction with our May 2011 tender offers, we expect to transfer $18 million of the gain to loss on redemption of debt.

Gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. The components of interest expense for the Current Quarter and the Prior Quarter are presented below.

	Three Months Ended March 31, 2011	2010
	($ in millions)	
Interest expense on senior notes	$ 177	$ 192
Interest expense on credit facilities	21	12
Capitalized interest	(205)	(161)
Realized (gains) losses on interest rate derivatives	(7)	(3)
Unrealized (gains) losses on interest rate derivatives	6	(27)
Amortization of loan discount and other	15	12
Total interest expense	$ 7	$ 25

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 paid Chesapeake 19 million and Chesapeake paid the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. 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. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $7 million at March 31, 2011. The euro-denominated debt in notes payable has been adjusted to $851 million at March 31, 2011 using an exchange rate of $1.4183 to 1.00. On May 3, 2011, we purchased and subsequently retired 256 million of our euro-denominated senior notes through a tender offer. Simultaneously with our purchase of the euro-denominated senior notes, we unwound foreign currency swaps for the same principal amount as the retired notes.

Additional Disclosures Regarding Derivative Instruments

In accordance with accounting guidance for derivatives and hedging, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative instruments with the same counterparty in the accompanying consolidated balance sheets. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows.

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 Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC 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 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 were effective as of March 31, 2011.

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*

There have been no material developments in (i) the putative class action originally filed in February 2009 under Sections 11, 12 and 15 of the Securities Act of 1933 against the company, certain of its officers and directors and certain underwriters of the company s July 2008 common stock offering pending in the U.S. District Court for the Western District of Oklahoma, (ii) the related derivative action filed in March 2009 against the company s directors and certain of its officers in the District Court of Oklahoma County, Oklahoma which has been stayed by stipulation of the parties, (iii) the shareholder inspection demand suit filed in March 2009 relating to compensation of the company s CEO pending in the Oklahoma Court of Civil Appeals, and (iv) three derivative actions filed in April and May 2009 against the company s directors alleging, among other things, breaches of fiduciary duties relating to compensation of the company s CEO pending in the Oklahoma Court of Civil Appeals. We refer you to Item 3 of the company s 2010 Form 10-K for a description of these matters.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. We refer you 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 for additional information on such matters.

There are pending against us enforcement actions initiated in the 2010 fourth quarter and 2011 first quarter by the Pennsylvania Department of Environmental Protection (DEP) related to alleged methane migration into the groundwater and residential water wells and by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act permitting requirements in West Virginia. We have responded to all pending orders and are actively cooperating with the relevant agencies. We believe that each of these actions will result in monetary sanctions exceeding $100,000. We are estimating a fine of approximately $1 million in the Pennsylvania action but are unable to estimate the amount of any fines that might be imposed by the EPA in the West Virginia action.

Following a well control incident in Bradford County, Pennsylvania on April 20, 2011, Chesapeake voluntarily suspended well completion operations in the state and has responded to a notice of violation issued by the Pennsylvania DEP. We have provided information regarding our investigation of the incident and the potential environmental impact of the event. We believe our investigation has identified the origin of the well control incident as occurring within the wellhead, and we have conducted wellhead inspections on other wells in the completion phase in the Marcellus Shale and implemented responsive measures. We are working closely with the Pennsylvania DEP to obtain its concurrence that we may resume completion operations in the state as soon as possible. We are unable to predict at this time the amount of any fines or penalties that will result from this incident.

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 2010 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

The following table presents information about repurchases of our common stock during the Current Quarter:

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)]
January 1, 2011 through January 31, 2011	1,015,701	$ 26.24		
February 1, 2011 through February 28, 2011	10,917	$ 35.24		
March 1, 2011 through March 31, 2011	8,113	$ 33.73		
Total	1,034,731	$ 26.39		

(a) Reflects the surrender to the company of 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 deferred compensation 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. ***(Removed and Reserved)***

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	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010, with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X

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Exhibit		Incorporated by Reference					
Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema Document.						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.						X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.						X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.						X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						X

* Chesapeake agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

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SIGNATURES

Pursuant to the requirement 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
Date: May 10, 2011	By: /s/ AUBREY K. MCCLENDON Aubrey K. McClendon *Chairman of the Board and* *Chief Executive Officer*
Date: May 10, 2011	By: /s/ DOMENIC J. DELL OSSO, JR. Domenic J. Dell Osso, Jr. *Executive Vice President and* *Chief Financial Officer*

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INDEX TO EXHIBITS

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010, with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema Document.						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.						X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.						X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.						X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						X

* Chesapeake agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.