CHESAPEAKE ENERGY CORP
Form 10-Q
August 09, 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 June 30, 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 August 3, 2011, there were 660,841,196 shares of our common stock, $0.01 par value, outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2011	December 31, 2010
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 109	$ 102
Accounts receivable	2,708	1,974
Short-term derivative instruments	169	947
Deferred income tax asset	15	139
Other current assets	125	104
Total Current Assets	3,126	3,266
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	38,318	38,952
Unevaluated properties	14,941	14,469
Natural gas gathering systems and treating plants	1,452	1,545
Other property and equipment	4,461	3,726
Total Property and Equipment, at Cost	59,172	58,692
Less: accumulated depreciation, depletion and amortization	(27,120)	(26,314)
Total Property and Equipment, Net	32,052	32,378
OTHER ASSETS:		
Investments	1,105	1,208
Long-term derivative instruments	7	
Other long-term assets	366	327
Total Other Assets	1,478	1,535
TOTAL ASSETS	$ 36,656	$ 37,179
CURRENT LIABILITIES:		
Accounts payable	$ 2,600	$ 2,069
Short-term derivative instruments	133	15
Accrued interest	180	191
Other current liabilities	2,815	2,215
Total Current Liabilities	5,728	4,490
LONG-TERM LIABILITIES:		
Long-term debt, net	10,047	12,640

Deferred income tax liabilities	2,482	2,384
Long-term derivative instruments	2,138	1,693
Asset retirement obligations	305	301
Other long-term liabilities	473	407
Total Long-Term Liabilities	15,445	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, 659,107,987 and 655,251,275 shares issued	7	7
Paid-in capital	12,125	12,194
Retained earnings	411	190
Accumulated other comprehensive income (loss), net of tax of $61 million and $102 million	(99)	(168)
Less: treasury stock, at cost; 1,282,300 and 1,221,299 common shares	(26)	(24)
Total Stockholders Equity	15,483	15,264
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 36,656	$ 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ in millions, except per share data)			
REVENUES:				
Natural gas and oil sales	$ 1,792	$ 1,161	$ 2,286	$ 3,059
Marketing, gathering and compression sales	1,404	793	2,421	1,637
Service operations revenue	122	58	223	114
Total Revenues	3,318	2,012	4,930	4,810
OPERATING COSTS:				
Production expenses	262	213	500	421
Production taxes	46	37	91	85
General and administrative expenses	130	106	259	215
Marketing, gathering and compression expenses	1,366	763	2,352	1,578
Service operations expense	92	53	169	102
Natural gas and oil depreciation, depletion and amortization	366	340	724	647
Depreciation and amortization of other assets	63	53	131	103
(Gains) losses on sales of other property and equipment	4		(1)	
Other impairments	4		4	
Total Operating Costs	2,333	1,565	4,229	3,151
INCOME FROM OPERATIONS	985	447	701	1,659
OTHER INCOME (EXPENSE):				
Interest (expense) income	(25)	16	(33)	(9)
Earnings from equity investees	47	27	72	39
Losses on purchases or exchanges of debt	(174)	(69)	(176)	(71)
Other income (expense)	2	(7)	5	(4)
Total Other Income (Expense)	(150)	(33)	(132)	(45)
INCOME BEFORE INCOME TAXES	835	414	569	1,614

INCOME TAX EXPENSE:								
Current income taxes		6		5		12		5
Deferred income taxes		319		154		210		616
Total Income Tax Expense		325		159		222		621
NET INCOME		510		255		347		993
Preferred stock dividends		(43)		(20)		(85)		(25)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$	467	$	235	$	262	$	968
EARNINGS PER COMMON SHARE:								
Basic	$	0.74	$	0.37	$	0.41	$	1.54
Diluted	$	0.68	$	0.37	$	0.41	$	1.49
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.0875	$	0.075	$	0.1625	$	0.15
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):								
Basic		635		631		635		630
Diluted		751		635		645		665

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ in millions)			
Net income	$ 510	$ 255	$ 347	$ 993
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $87 million, ($38) million, $89 million and $114 million	141	(62)	146	187
Reclassification of gain on settled contracts, net of income taxes of ($11) million, ($82) million, ($39) million and ($135) million	(18)	(134)	(64)	(221)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($3) million, $7 million, ($7) million and $9 million	(5)	11	(11)	15
Unrealized gain (loss) on marketable securities, net of income taxes of ($3) million, ($3) million, ($1) million and ($5) million	(5)	(5)	(2)	(8)
Comprehensive income	$ 623	$ 65	$ 416	$ 966

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)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 347	$ 993
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	855	750
Deferred income tax expense	210	616
Unrealized losses on derivatives	1,087	5
Stock-based compensation	79	67
Accretion of discount on contingent convertible notes		38
(Gains) losses on equity investments	(23)	35
Losses on purchases or exchanges of debt	33	39
Other		21
Change in assets and liabilities	(495)	414
Cash provided by operating activities	2,093	2,978
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(3,395)	(2,331)
Acquisitions of proved and unproved properties	(2,529)	(2,855)
Proceeds from divestitures of proved and unproved properties	6,173	1,933
Additions to other property and equipment	(863)	(679)
Proceeds from sales of other assets	526	306
Proceeds from (additions to) investments	212	(109)
Acquisition of drilling company	(339)	
Other	(25)	3
Cash used in investing activities	(240)	(3,732)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	8,343	7,044
Payments on credit facilities borrowings	(10,235)	(7,415)
Proceeds from issuance of senior notes, net of offering costs	977	
Proceeds from issuance of preferred stock, net of offering costs		2,562
Cash paid to purchase debt	(2,032)	(1,334)
Cash paid for common stock dividends	(95)	(95)
Cash paid for preferred stock dividends	(86)	(11)
Cash received on financing derivatives	882	271
Net increase in outstanding payments in excess of cash balance	448	47
Other	(48)	(21)

Cash provided by (used in) financing activities		(1,846)		1,048
Net increase in cash and cash equivalents		7		294
Cash and cash equivalents, beginning of period		102		307
Cash and cash equivalents, end of period	$	109	$	601

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)

	Six Months Ended June 30, 2011		Six Months Ended June 30, 2010	
	($ in millions)			
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF NET CASH PAYMENTS (REFUNDS) FOR:				
Interest, net of capitalized interest	$		$	57
Income taxes, net of refunds received	$	(25)	$	(291)

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

As of June 30, 2011 and 2010, dividends payable on our common and preferred stock were $99 million and $90 million, respectively.

For the six months ended June 30, 2011 and 2010, natural gas and oil properties were adjusted by $92 million and $64 million, respectively, as a result of an increase in accrued costs.

For the six months ended June 30, 2011 and 2010, other property and equipment were adjusted by $37 million and $2 million, respectively, as a result of an increase in accrued costs.

As of June 30, 2011 and 2010, we had recorded $206 million and $178 million, respectively, as a result of various accrued liabilities related to the purchase of proved and unproved properties and other assets.

During the six months ended June 30, 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.

On May 3, 2010, we converted all 5,000 shares of our outstanding 5.00% Cumulative Convertible Preferred Stock (Series 2005) into 20,774 shares of common stock pursuant to the company s mandatory conversion rights.

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)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 3,065	$ 466
Issuance of 0 and 1,500,000 shares of 5.75% preferred stock		1,500
Issuance of 0 and 1,100,000 shares of 5.75% preferred stock (series A)		1,100
Exchange of 0 and 5,000 shares of 5% preferred stock (series 2005) for common stock		(1)
Balance, end of period	3,065	3,065
COMMON STOCK:		
Balance, beginning of period	7	6
Exchange of convertible notes for 0 and 298,500 shares of common stock		
Exchange of preferred stock for 0 and 20,774 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	114	116
Purchase of contingent convertible notes	(123)	
Exchange of convertible notes for 0 and 298,500 shares of common stock		8
Exchange of 0 and 5,000 shares of preferred stock for common stock		1
Exercise of stock options	1	2
Offering expenses		(38)
Tax benefit from stock-based compensation	2	
Dividends on common stock	(48)	(95)
Dividends on preferred stock	(15)	(44)
Balance, end of period	12,125	12,096
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	190	(1,261)
Net income	347	993
Cumulative effect of accounting change, net of income taxes of $89 million		(142)
Dividends on common stock	(56)	
Dividends on preferred stock	(70)	

Balance, end of period	411	(410)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(168)	102
Hedging activity	71	(19)
Investment activity	(2)	(8)
Balance, end of period	(99)	75
TREASURY STOCK COMMON:		
Balance, beginning of period	(24)	(15)
Purchase of 134,300 and 123,579 shares for company benefit plans	(4)	(3)
Release of 73,299 and 6,818 shares for company benefit plans	2	
Balance, end of period	(26)	(18)
NONCONTROLLING INTEREST:		
Balance, beginning of period		897
Deconsolidation of investment in Chesapeake Midstream Partners		(897)
Balance, end of period		
TOTAL STOCKHOLDERS EQUITY	$ 15,483	$ 14,815

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 and six months ended June 30, 2011 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2011 (the Current Quarter and the Current Period , respectively) and the three and six months ended June 30, 2010 (the Prior Quarter and the Prior Period , respectively).

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 Period. 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. Derivative and Hedging Activities

Natural Gas and Oil Derivatives

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. As of June 30, 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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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(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 June 30, 2011 and December 31, 2010 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2011		**December 31, 2010**	
	Volume	**Fair Value ($ in millions)**	**Volume**	**Fair Value ($ in millions)**
Natural gas (bbtu):				
Fixed-price swaps	512,718	$ 346	1,035,134	$ 1,307
Call options	1,525,383	(769)	1,477,742	(701)
Put options	(33,120)	(35)	(51,220)	(59)
Basis protection swaps	130,684	(50)	173,691	(55)
Total natural gas	2,135,665	(508)	2,635,347	492
Oil (mbbl):				
Fixed-price swaps	2,202	4	4,385	(31)
Call options	77,489	(1,552)	64,226	(1,129)
Fixed-price knockout swaps	1,284	10	1,827	19
Total oil	80,975	(1,538)	70,438	(1,141)
		$ (2,046)		$ (649)

Total estimated fair value

Pursuant to accounting guidance for derivatives and hedging, 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ in millions)			
Natural gas and oil sales	$ 1,278	$ 984	$ 2,465	$ 2,169
Gains (losses) on natural gas and oil derivatives	506	195	(197)	914
Gains (losses) on ineffectiveness of cash flow hedges	8	(18)	18	(24)
Total natural gas and oil sales	$ 1,792	$ 1,161	$ 2,286	$ 3,059

Based upon the market prices at June 30, 2011, we expect to transfer approximately $75 million (net of income taxes) of gain included in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All derivatives as of June 30, 2011 are expected to mature by December 31, 2022.

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for commodity price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.3 billion under the terms of the facility. As of June 30, 2011, we had hedged under the facility 2.5 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. 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 a portion of our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of June 30, 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

(Unaudited)

The notional amount of debt hedged and the estimated fair value of our interest rate derivatives outstanding as of June 30, 2011 and December 31, 2010 are provided below.

	June 30, 2011		December 31, 2010	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 1,600	$ (48)	$ 1,900	$ (54)
Call options			250	(2)
Swaptions	450	(8)	500	(13)
Total	$ 2,050	$ (56)	$ 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, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ in millions)			
Interest expense on senior notes	$ 164	$ 190	$ 342	$ 383
Interest expense on credit facilities	10	12	31	24
(Gains) losses on interest rate derivatives	19	(51)	18	(81)
Amortization of loan discount and other	8	12	23	23
Capitalized interest	(176)	(179)	(381)	(340)
Total interest expense (income)	$ 25	$ (16)	$ 33	$ 9

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 $30 million in gains related to such transactions.

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired 256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the condensed consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake 11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 344 million and Chesapeake will pay the counterparties $459 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as an asset of $7 million at June 30, 2011. The euro-denominated debt in long-term debt has been adjusted to $500 million at June 30, 2011 using an exchange rate of $1.4523 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 June 30, 2011 and December 31, 2010 on a gross basis without regard to same-counterparty netting:

		Fair Value	
	Balance Sheet Location	June 30, 2011	December 31, 2010
		($ in millions)	
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 168	$ 307
Commodity contracts	Long-term derivative instruments	1	12
Foreign currency contracts	Long-term derivative instruments	7	
Total		176	319
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	198	921
Commodity contracts	Long-term derivative instruments	101	229
Total		299	1,150
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(17)	(59)
Interest rate contracts	Long-term derivative instruments	(11)	(25)
Foreign currency contracts	Long-term derivative instruments		(43)
Total		(28)	(127)

Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(306)	(222)
Commodity contracts	Long-term derivative instruments	(2,191)	(1,837)
Interest rate contracts	Short-term derivative instruments	(8)	(15)
Interest rate contracts	Long-term derivative instruments	(37)	(29)
Total		(2,542)	(2,103)
Total derivative instruments		$ (2,095)	$ (761)

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

Fair Value Hedges

The following table presents the gain (loss) recognized in the condensed consolidated statement of operations for instruments designated as fair value derivatives:

Fair Value Derivatives	Location of Gain (Loss)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Interest rate contracts	Interest expense[(a)]	$ 5	$ 5	$ 11	$ 13

(a) Interest expense on items hedged during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period was $9 million, $5 million, $21 million and $15 million, respectively, which is included in interest expense on the condensed consolidated statements of operations.

Cash Flow Hedges

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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Gain (Loss) Recognized in AOCI (Effective Portion)					
Commodity contracts	AOCI	$ 234	$ (41)	$ 250	$ 364
Foreign currency contracts	AOCI	(14)	(41)	(33)	(39)
		$ 220	$ (82)	$ 217	$ 325
Gain (Loss) Reclassified from AOCI (Effective Portion)					
Commodity contracts	Natural gas and oil sales	$ 67	$ 216	$ 141	$ 356
Foreign currency contracts	Interest expense	(18)		(18)	
Foreign currency contracts	Loss on purchase of debt	(20)		(20)	
		$ 29	$ 216	$ 103	$ 356

Gain (Loss) Recognized in Income					
Commodity contracts					
Ineffective portion	Natural gas and oil sales	$ 8	$ (18)	$ 18	$ (24)
Amount initially excluded from effectiveness testing	Natural gas and oil sales		36	22	72
		$ 8	$ 18	$ 40	$ 48

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Non-Qualifying Derivatives

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

		Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Contracts	**Location of Gain (Loss)**	**2011**	**2010**	**2011**	**2010**
Commodity contracts	Natural gas and oil sales	$ 439	$ (57)	$ (360)	$ 486
Interest rate contracts	Interest expense	(6)	46	(11)	68
	Total	$ 433	$ (11)	$ (371)	$ 554

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 June 30, 2011, our commodity and interest rate derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility described above included 11 of our counterparties which are required to secure their natural gas and oil derivative obligations in excess of defined thresholds. We use this facility for all of our commodity derivatives.

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.

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The company records an associated liability when a loss is probable and the amount is reasonably estimable. Based on management s current assessment, we are 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.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to 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 June 30, 2011. There is, however, pending against us an enforcement action related to 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 93 drilling rigs and related equipment for $802 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of five 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 June 30, 2011, the minimum aggregate undiscounted future rig lease payments were approximately $506 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 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 compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2011, the minimum aggregate undiscounted future compressor lease payments were approximately $391 million.

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Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas and liquids from certain of our production. We have entered into these agreements to move our production to market. Working interest owners who are selling with us under our marketing agreements will reimburse us for some of these costs. While we expect to have sufficient production to fully utilize the committed capacity, we can pursue a release of any unused capacity to others, thus potentially reducing our future commitment.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest owners, are presented below:

	June 30, 2011 ($ in millions)
2011	$ 440
2012	1,017
2013	1,153
2014	1,150
2015	1,195
2015 - 2099	6,767
Total	$ 11,722

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 55 rigs with terms ranging from four months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2011, the aggregate undiscounted minimum future drilling rig commitment was approximately $450 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.

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.

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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 and the Prior Period, all outstanding securities that were convertible into common stock were included in the calculation of diluted EPS. For the Prior Quarter and the Current Period, the following securities and associated adjustments to net income, consisting of dividends on our cumulative convertible preferred stock, 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 June 30, 2010:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 6	16
5.75% cumulative convertible preferred stock (series A)	$ 8	19
5.00% cumulative convertible preferred stock (series 2005B)	$ 3	5
4.50% cumulative convertible preferred stock	$ 3	6
Six Months Ended June 30, 2011:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$ 43	56
5.75% cumulative convertible preferred stock (series A)	$ 31	39
5.00% cumulative convertible preferred stock (series 2005B)	$ 5	5
4.50% cumulative convertible preferred stock	$ 6	6

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

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended June 30, 2011:			
Basic EPS	$ 467	635	$ 0.74
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 5.75% cumulative convertible preferred stock	21	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	16	39	
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		9	
Outstanding stock options		1	
Diluted EPS	$ 510	751	$ 0.68
Three Months Ended June 30, 2010:			
Basic EPS	$ 235	631	$ 0.37
Effect of Dilutive Securities:			
Unvested restricted stock		3	
Outstanding stock options		1	
Diluted EPS	$ 235	635	$ 0.37

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	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Six Months Ended June 30, 2011:			
Basic EPS	$ 262	635	$ 0.41
Effect of Dilutive Securities:			
Unvested restricted stock		9	
Outstanding stock options		1	
Diluted EPS	$ 262	645	$ 0.41
Six Months Ended June 30, 2010:			
Basic EPS	$ 968	630	$ 1.54
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 5.75% cumulative convertible preferred stock	6	8	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	8	10	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	5	6	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	6	6	
Unvested restricted stock		4	
Outstanding stock options		1	
Diluted EPS	$ 993	665	$ 1.49

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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 six months ended June 30, 2011 and 2010:

	2011	2010
	(in thousands)	
Shares outstanding at January 1	655,251	648,549
Restricted stock issuances (net of forfeitures)	3,543	2,812
Stock option exercises	314	316
Convertible note exchanges		299
Preferred stock conversions/exchanges		21
Shares outstanding at June 30	659,108	651,997

In the Prior Period, 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 six months ended June 30, 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 June 30, 2011	1,500	1,100	2,559	2,096	
Shares outstanding at January 1, 2010			2,559	2,096	5
Preferred stock issuances	1,500	1,100			
Conversion of preferred into common stock					(5)
Shares outstanding at June 30, 2010	1,500	1,100	2,559	2,096	

On May 17, 2010, we issued 600,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock, par value $0.01 per share and liquidation preference $1,000 per share, in a private placement for net proceeds of approximately $594 million. We issued an additional 900,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock on June 18, 2010, upon the exercise of the purchasers option to place the additional shares, for net proceeds of approximately $877 million.

On May 17, 2010, we issued 1,100,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock (Series A), par value $0.01 per share and liquidation preference $1,000 per share, in a private placement for net proceeds of approximately $1.091 billion.

On May 3, 2010, we converted all 5,000 shares of our outstanding 5.00% Cumulative Convertible Preferred Stock (Series 2005) into 20,774 shares of common stock pursuant to the company s mandatory conversion rights.

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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. We may pay dividends on our 5% Cumulative Convertible Preferred Stock (Series 2005B) and our 4.50% Cumulative Convertible Preferred Stock in cash, common stock or a combination thereof, at our option. Dividends on both series of our 5.75% Cumulative Convertible Non-Voting Preferred Stock are payable only in cash.

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, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ in millions)			
Natural gas and oil properties	$ 29	$ 28	$ 60	$ 66
General and administrative expenses	23	21	47	42
Production expenses	9	9	18	18
Marketing, gathering and compression expenses	4	4	9	9
Service operations expense	2	2	5	4
Total	$ 67	$ 64	$ 139	$ 139

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 six months ended June 30, 2011 is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value

	(in thousands)	
Unvested shares as of January 1, 2011	21,375	$ 28.68
Granted	4,989	$ 26.92
Vested	(3,208)	$ 27.59
Forfeited	(330)	$ 27.41
Unvested shares as of June 30, 2011	22,826	$ 28.47

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

As of June 30, 2011, there was $350 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 the Current Quarter, we recognized excess tax benefits of a nominal amount which were recorded as an adjustment to additional paid-in-capital and deferred income taxes. A $1 million reduction in tax benefits related to restricted stock was recorded as an adjustment to additional paid-in-capital and deferred income taxes in the Prior Quarter, Current Period and the Prior Period.

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 six months ended June 30, 2011:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)			($ in millions)
Outstanding at January 1, 2011	1,808	$ 8.90	2.03	$ 31
Exercised	(400)	$ 6.86		
Outstanding and exercisable at June 30, 2011	1,408	$ 9.48	1.76	$ 28

(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 the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $2 million, a nominal amount, $3 million and $1 million, respectfully, 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 June 30, 2011 and December 31, 2010:

	June 30, 2011	December 31, 2010
	($ in millions)	
7.625% senior notes due 2013	$ 464	$ 500
9.5% senior notes due 2015	1,265	1,425
6.25% euro-denominated senior notes due 2017[(a)]	500	796
6.5% senior notes due 2017	660	1,100
6.875% senior notes due 2018	474	600
7.25% senior notes due 2018	669	800
6.625% senior notes due 2020	1,300	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)]	396	451
2.5% contingent convertible senior notes due 2037[(b)]	1,168	1,378
2.25% contingent convertible senior notes due 2038[(b)]	346	752
Corporate revolving bank credit facility	1,710	3,612
Midstream revolving bank credit facility	104	94
Discount on senior notes[(c)]	(528)	(777)
Interest rate derivatives[(d)]	19	9
Total long-term debt	$ 10,047	$ 12,640

(a) The principal amount shown is based on the exchange rate of $1.4523 to 1.00 and $1.3269 to 1.00 as of June 30, 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 second 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 third 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	$ 64.16	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Included in this discount is $476 million at June 30, 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.

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In May 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.

	Principal Amount Purchased ($ in millions)
7.625% senior notes due 2013	$ 36
9.5% senior notes due 2015	160
6.25% euro-denominated senior notes due 2017[(a)]	380
6.5% senior notes due 2017	440
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
Total senior notes	1,373
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
Total contingent convertible senior notes	531
Total	$ 1,904

(a) We purchased   256 million in aggregate principal amount of our euro-denominated senior notes which had a value of $380 million based on the exchange rate of $1.4821 to   1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound cross currency swaps for the same principal amount. See Note 2 for additional information.

We paid $2.058 billion in cash for the tender offers described above and recorded associated losses of approximately $174 million. The losses included $154 million in cash premiums, $20 million of deferred charges, $160 million of note discounts and $2 million of interest rate hedging losses, offset by $162 million of the equity component of the contingent convertible notes.

During the Current Period, we issued $1.0 billion principal amount 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 Period, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these repurchases, we recognized a loss of $2 million in the Current Period.

During the Prior Period, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our

7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Prior Period.

During the Prior Period, 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 Period.

No scheduled principal payments are required under our senior notes until 2013 when $464 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	June 2016
Borrowing capacity	$ 4,000	$ 600[c]
Amount outstanding as of June 30, 2011	$ 1,710	$ 104
Letters of credit outstanding as of June 30, 2011	$ 56	$

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

(b) Borrower is Chesapeake Midstream Operating, L.L.C.

(c) The decrease in operating income following the sale of our Haynesville Springridge gathering system and the sale of our Fayetteville gathering system on March 31, 2011 caused the borrowing capacity under the facility to be limited to $350 million as of June 30, 2011.

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 June 30, 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

On June 15, 2011, our midstream credit facility agreement was amended and restated to, among other things, increase the amount we can borrow under the facility from $300 million to $600 million, improve interest rates, extend the maturity by almost a year and favorably restructure covenants. We use the midstream syndicated revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of 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 1.00% to 1.75% per annum or (ii) the Eurodollar rate, which is based on the LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. 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 a result of the sale of our Springridge gathering system to Chesapeake Midstream Partners in December 2010, we were subject to a higher leverage ratio during the three quarters ended June 30, 2011. We were in compliance with all covenants under the agreement at June 30, 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 June 30, 2011, we had 111 assets remaining and the 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.

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

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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, trucking and other oilfield service operations which are responsible for providing services for both Chesapeake-operated wells and wells operated by third parties. Our drilling rig, trucking and other oilfield 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 $1.213 billion, $926 million, $2.417 billion and $1.933 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. The following table presents selected financial information for Chesapeake s operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)		
Three Months Ended June 30, 2011:					
Revenues	$ 1,792	$ 2,617	$ 275	$ (1,366)	$ 3,318
Intersegment revenues		(1,213)	(153)	1,366	
Total revenues	$ 1,792	$ 1,404	$ 122	$	$ 3,318
Income (loss) before income taxes	$ 808	$ 75	$ 21	$ (69)	$ 835
Three Months Ended June 30, 2010:					
Revenues	$ 1,161	$ 1,719	$ 181	$ (1,049)	$ 2,012
Intersegment revenues		(926)	(123)	1,049	
Total revenues	$ 1,161	$ 793	$ 58	$	$ 2,012
Income (loss) before income taxes	$ 403	$ 23	$ (14)	$ 2	$ 414
Six Months Ended June 30, 2011:					
Revenues	$ 2,286	$ 4,838	$ 523	$ (2,717)	$ 4,930
Intersegment revenues		(2,417)	(300)	2,717	
Total revenues	$ 2,286	$ 2,421	$ 223	$	$ 4,930
Income (loss) before income taxes	$ 511	$ 160	$ 42	$ (144)	$ 569
Six Months Ended June 30, 2010:					

Revenues	$ 3,059	$ 3,570	$ 351	$ (2,170)	$ 4,810
Intersegment revenues		(1,933)	(237)	2,170	
Total revenues	$ 3,059	$ 1,637	$ 114	$	$ 4,810
Income (loss) before income taxes	$ 1,579	$ 55	$ (25)	$ 5	$ 1,614
As of June 30 2011:					
Total assets	$ 32,855	$ 3,678	$ 1,301	$ (1,178)	$ 36,656
As of December 31, 2010:					
Total assets	$ 33,560	$ 3,458	$ 854	$ (693)	$ 37,179

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8. Acquisitions and Divestitures

Acquisition of Bronco Drilling

In June 2011, we acquired Bronco Drilling Company, Inc. (Nasdaq/GS: BRNC) through a tender offer for all of the outstanding stock of Bronco. We paid $11.00 per share for each outstanding share of Bronco stock for an aggregate purchase price of approximately $339 million. The acquisition was accounted for as a business combination which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Pro forma financial information is not presented as it would not be materially different from the information presented in the condensed consolidated statement of income.

The following table summarizes the assets acquired and liabilities assumed:

	As of June 6, 2011 ($ in millions)
Current assets	$ 46
Drilling rigs and equipment	287
Goodwill	52
Intangible assets	10
Other	12
Total assets acquired	407
Current liabilities	33
Long-term liabilities	1
Deferred income taxes	34
Total liabilities assumed	68
Net assets acquired	$ 339

The acquisition date fair value of the consideration transferred was $339 million in cash. We received carryover tax basis in Bronco s assets and liabilities because the acquisition was not a taxable transaction under the Internal Revenue Code. Based upon the purchase price allocation, a step-up in basis related to the assets acquired from Bronco resulted in a net deferred tax liability of approximately $34 million. We recorded goodwill of $52 million, which represents the amount of the consideration transferred in excess of the fair values assigned to the individual assets acquired and liabilities assumed. Goodwill is primarily attributable to operational and cost synergies expected to be realized from the acquisition by integrating Bronco s drilling rigs and assembled workforce. None of the goodwill is deductible for tax purposes. Goodwill was assigned to drilling rig operations which is discussed in Note 7. Goodwill recorded in the acquisition is not subject to amortization, but will be tested annually for impairment.

Fayetteville Shale Asset Sale

On March 31, 2011, we sold all of our Fayetteville Shale assets in Central Arkansas to BHP Billiton Petroleum (NYSE:BHP; ASX:BHP), a wholly owned subsidiary of BHP Billiton Limited, for net proceeds of approximately $4.65 billion in cash. The properties sold consisted of approximately 487,000 net acres of leasehold, net production at closing 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. Under full cost accounting rules, we accounted for the sale of our Fayetteville Shale natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss.

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Joint Ventures

As of June 30, 2011, we had entered into six significant joint ventures pursuant to which we sold a portion of our leasehold, producing properties and other assets located 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. For accounting purposes, initial cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. The transactions are detailed below.

In February 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 Sand 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 2013. 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.

In November 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 mid-year 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.

In January 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 mid-year 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.

In November 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.

In September 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.

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In July 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 up to $1.65 billion of our future drilling and completion costs in the Haynesville and Bossier Shale. 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 Period and the Prior Period, our drilling and completion costs included the benefit of approximately $1.129 billion and $534 million, respectively, in drilling and completion carries paid by our joint venture partners, CNOOC, Total and Statoil as follows:

Primary Play	Joint Venture Partner	Joint Venture Date	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
			($ in millions)	
Marcellus	Statoil	November 2008	493	235
Barnett	Total	January 2010	277	299
Eagle Ford	CNOOC	November 2010	299	
Niobrara	CNOOC	February 2011	$ 60	$
			$ 1,129	$ 534

During the Current Period and the Prior Period, as part of our joint venture agreements with CNOOC, Total, Statoil and Plains Exploration & Production Company, we sold interests in additional leasehold in the Niobrara, Eagle Ford and Pearsall, Barnett, Marcellus and Haynesville and Bossier shale plays to our joint venture partners for approximately $345 million and $320 million, respectively.

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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 (VPPs). A VPP is a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser s only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain the remaining reserves, if any, after the scheduled production volumes have been delivered. 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 VPP transactions since 2007:

Date of VPP	Location	Proceeds ($ in millions)	Proved Reserves (at time of sale) (bcfe)	$ / mcfe	Original Term (years)
May 2011	Mid-Continent	$ 853	177	$ 4.82	10
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
		$ 5,622	1,212	$ 4.64	

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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9. Investments

At June 30, 2011 and December 31, 2010, we had the following investments:

	Approximate % Owned	Accounting Method	Carrying Value June 30, 2011	Carrying Value December 31, 2010
			($ in millions)	
Chesapeake Midstream Partners, L.P.	42%	Equity	$ 694	$ 695
Frac Tech International, LLC	30%[(a)]	Equity	236	311
Chaparral Energy, Inc.	20%	Equity	122	133
Gastar Exploration Ltd.	11%	Cost	23	29
Other		Cost/Equity	30	40
			$ 1,105	$ 1,208

(a) Prior to the recapitalization described below, we owned approximately 26% of Frac Tech Holdings, LLC.

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 representing limited partner interests (including 3,187,500 common units issued pursuant to the exercise of the underwriters over-allotment option on August 3, 2010) 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 Period, we recorded positive equity method adjustments of $34 million for our share of CHKM s income, received cash distributions of $41 million from CHKM and recorded accretion adjustments of $6 million for our share of equity in excess of cost. The carrying value of our investment in CHKM is less than our underlying equity in net assets by approximately $231 million as of June 30, 2011. This difference is being accreted over 20 years.

Frac Tech International, LLC. Frac Tech International, LLC (FTI), based in Fort Worth, Texas, is the privately held parent company of Frac Tech Services, LLC, which provides pressure pumping and well stimulation to oil and gas companies. On May 6, 2011, there was a change in controlling ownership of FTI s predecessor, Frac Tech Holdings, L.L.C. During the Current Quarter, we also received a cash distribution of approximately $206 million, increased our equity ownership from 26% to 30% and entered into a Master Frac Services Agreement that obligates us to use certain services of FTI through 2014. Based on the preliminary valuation of the net assets performed by FTI in conjunction with the change in controlling ownership, we believe the carrying value of our investment in FTI is less than our underlying equity in FTI s net assets as of the date of the ownership change by approximately $832 million. We will allocate this difference to the tangible and intangible assets of FTI and will accrete the portion attributable to the non-goodwill assets over their estimated lives.

In the Current Period, we recorded positive equity method adjustments of $78 million for our share of FTI s income and recorded accretion adjustments of $1 million.

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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 Period, we recorded negative equity method adjustments of $11 million for our share of Chaparral s net loss and depreciation adjustments of $2 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 $56 million as of June 30, 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.

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 Period, the common stock price of Gastar decreased from $4.30 per share to $3.43 per share. Our investment in Gastar had a historical cost basis of $89 million as of June 30, 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 cross 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 cross 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.

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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.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 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	$ 109	$	$	$ 109
Investments	23			23
Other long-term assets	56			56
Long-term debt		(789)		(789)
Other long-term liabilities	(56)			(56)
Derivatives:				
Commodity assets		368	100	468
Commodity liabilities		(18)	(2,496)	(2,514)
Interest rate liabilities		(48)	(8)	(56)
Foreign currency assets		7		7
Total derivatives		309	(2,404)	(2,095)
Total	$ 132	$ (480)	$ (2,404)	$ (2,752)

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during the Current Period and the Prior Period 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)]	(21)			
Included in earnings or change in net assets (unrealized)[(a)]	(527)	11		
Included in other comprehensive income (loss)				
Total purchases, issuances, sales and settlements:				
Sales		(4)		
Settlements	106			
Transfers in and out of Level 3[(c)]		54	43	1,371
Ending Balance as of June 30, 2011	$ (2,396)	$ (8)	$	$
Beginning Balance as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses):				
Included in earnings (realized)[(a)]	214	(5)		
Included in earnings or change in net assets (unrealized)[(a)]	(453)	88	(122)	110
Included in other comprehensive income (loss)	(10)		(39)	
Total purchases, issuances, sales and settlements:				
Issuances				(700)[(b)]
Sales		(6)		
Settlements	(115)	12		1,250[(b)]
Transfers in and out of Level 3				
Ending Balance as of June 30, 2010	$ (1,030)	$ (43)	$ (118)	$ (738)

(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 cross 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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.

	June 30, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 10,028	$ 11,144	$ 12,631	$ 13,272
Convertible preferred stock	$ 3,065	$ 3,752	$ 3,065	$ 3,019

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(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 June 30, 2011 and December 31, 2010 and for the three and six months ended June 30, 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 JUNE 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 109	$	$	$ 109
Other	7	2,866	153	(9)	3,017
Total Current Assets	7	2,975	153	(9)	3,126
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting, net		26,945	4		26,949
Other property and equipment, net		3,741	1,362		5,103
Total Property and Equipment, Net		30,686	1,366		32,052
Other assets	174	942	701	(339)	1,478
Investments in subsidiaries and intercompany advances	1,851	282		(2,133)	
TOTAL ASSETS	$ 2,032	$ 34,885	$ 2,220	$ (2,481)	$ 36,656
CURRENT LIABILITIES:					
Current liabilities	$ 295	$ 5,206	$ 237	$ (10)	$ 5,728
Intercompany payable (receivable) from parent	(22,330)	21,119	1,095	116	
Total Current Liabilities	(22,035)	26,325	1,332	106	5,728

LONG-TERM LIABILITIES:					
Long-term debt, net	8,233	1,710	104		10,047
Deferred income tax liabilities	337	2,112	149	(116)	2,482
Other liabilities	15	2,887	353	(339)	2,916
Total Long-Term Liabilities	8,585	6,709	606	(455)	15,445
STOCKHOLDERS EQUITY:					
Total Stockholders Equity	15,482	1,851	282	(2,132)	15,483
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,032	$ 34,885	$ 2,220	$ (2,481)	$ 36,656

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,792	$	$	$ 1,792
Marketing, gathering and compression sales		1,382	42	(20)	1,404
Service operations revenue		121	1		122
Total Revenues		3,295	43	(20)	3,318
OPERATING COSTS:					
Production expenses		262			262
Production taxes		46			46
General and administrative expenses		124	6		130
Marketing, gathering and compression expenses		1,352	28	(14)	1,366
Service operations expense		91	1		92
Natural gas and oil depreciation, depletion and amortization		366			366
Depreciation and amortization of other assets		52	11		63
Losses on sales of other property and equipment		2	2		4
Other impairments			4		4
Total Operating Costs		2,295	52	(14)	2,333
INCOME (LOSS) FROM OPERATIONS		1,000	(9)	(6)	985
OTHER INCOME (EXPENSE):					
Interest expense	(167)	(21)	(3)	166	(25)
Earnings from equity investees		26	21		47
Losses on purchases or exchanges of debt	(174)				(174)
Other income	164	3	1	(166)	2
Equity in net earnings of subsidiary	617	2		(619)	
Total Other Income (Expense)	440	10	19	(619)	(150)
INCOME BEFORE INCOME TAXES	440	1,010	10	(625)	835
INCOME TAX EXPENSE (BENEFIT)	(70)	393	4	(2)	325
NET INCOME	$ 510	$ 617	$ 6	$ (623)	$ 510

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,161	$	$	$ 1,161
Marketing, gathering and compression sales		768	62	(37)	793
Service operations revenue		58			58
Total Revenues		1,987	62	(37)	2,012
OPERATING COSTS:					
Production expenses		213			213
Production taxes		37			37
General and administrative expenses		99	7		106
Marketing, gathering and compression expenses		751	32	(20)	763
Service operations expense		53			53
Natural gas and oil depreciation, depletion and amortization		340			340
Depreciation and amortization of other assets		41	12		53
Total Operating Costs		1,534	51	(20)	1,565
INCOME (LOSS) FROM OPERATIONS		453	11	(17)	447
OTHER INCOME (EXPENSE):					
Interest (expense) income	(140)	(33)	(1)	190	16
Earnings from equity investees		4	23		27
Losses on purchases or exchanges of debt	(69)				(69)
Other income (expense)	190	3	(10)	(190)	(7)
Equity in net earnings of subsidiary	267	4		(271)	
Total Other Income (Expense)	248	(22)	12	(271)	(33)
INCOME BEFORE INCOME TAXES	248	431	23	(288)	414
INCOME TAX EXPENSE (BENEFIT)	(7)	164	9	(7)	159
NET INCOME	$ 255	$ 267	$ 14	$ (281)	$ 255

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 2,286	$	$	$ 2,286
Marketing, gathering and compression sales		2,373	97	(49)	2,421
Service operations revenue		222	1		223
Total Revenues		4,881	98	(49)	4,930
OPERATING COSTS:					
Production expenses		500			500
Production taxes		91			91
General and administrative expenses		244	15		259
Marketing, gathering and compression expenses		2,321	66	(35)	2,352
Service operations expense		168	1		169
Natural gas and oil depreciation, depletion and amortization		724			724
Depreciation and amortization of other assets		107	24		131
(Gains) losses on sales of other property and equipment		4	(5)		(1)
Other impairments			4		4
Total Operating Costs		4,159	105	(35)	4,229
INCOME (LOSS) FROM OPERATIONS		722	(7)	(14)	701
OTHER INCOME (EXPENSE):					
Interest expense	(350)	(24)	(3)	344	(33)
Earnings from equity investees		32	40		72
Losses on purchases or exchanges of debt	(176)				(176)
Other income	342	5	2	(344)	5
Equity in net earnings of subsidiary	459	11		(470)	
Total Other Income (Expense)	275	24	39	(470)	(132)
INCOME BEFORE INCOME TAXES	275	746	32	(484)	569
INCOME TAX EXPENSE (BENEFIT)	(72)	287	12	(5)	222
NET INCOME	$ 347	$ 459	$ 20	$ (479)	$ 347

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 3,059	$	$	$ 3,059
Marketing, gathering and compression sales		1,581	110	(54)	1,637
Service operations revenue		114			114
Total Revenues		4,754	110	(54)	4,810
OPERATING COSTS:					
Production expenses		421			421
Production taxes		85			85
General and administrative expenses		202	13		215
Marketing, gathering and compression expenses		1,544	54	(20)	1,578
Service operations expense		102			102
Natural gas and oil depreciation, depletion and amortization		647			647
Depreciation and amortization of other assets		81	22		103
Total Operating Costs		3,082	89	(20)	3,151
INCOME FROM OPERATIONS		1,672	21	(34)	1,659
OTHER INCOME (EXPENSE):					
Interest expense	(298)	(93)	(1)	383	(9)
Earnings (losses) from equity investees		(4)	43		39
Losses on purchases or exchanges of debt	(71)				(71)
Other income (expense)	383	5	(9)	(383)	(4)
Equity in net earnings of subsidiary	984	12		(996)	
Total Other Income (Expense)	998	(80)	33	(996)	(45)
INCOME BEFORE INCOME TAXES	998	1,592	54	(1,030)	1,614
INCOME TAX EXPENSE	5	608	21	(13)	621
NET INCOME	$ 993	$ 984	$ 33	$ (1,017)	$ 993

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

SIX MONTHS ENDED JUNE 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 2,207	$ 111	$ (225)	$ 2,093
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(5,924)			(5,924)
Proceeds from divestitures of proved and unproved properties		6,173			6,173
Additions to other property and equipment		(380)	(483)		(863)
Other investing activities		(90)	65	399	374
Cash used in investing activities		(221)	(418)	399	(240)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		7,661	682		8,343
Payments on credit facilities borrowings		(9,563)	(672)		(10,235)
Proceeds from issuance of senior notes, net of offering costs	977				977
Cash paid to purchase debt	(2,032)				(2,032)
Other financing activities	(226)	1,310	191	(174)	1,101
Intercompany advances, net	1,281	(1,287)	6		
Cash provided by (used in) financing activities		(1,879)	207	(174)	(1,846)
Net increase (decrease) in cash and cash equivalents		107	(100)		7
Cash and cash equivalents, beginning of period		2	100		102
Cash and cash equivalents, end of period	$	$ 109	$	$	$ 109

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

SIX MONTHS ENDED JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 2,874	$ 104	$	$ 2,978
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(5,186)			(5,186)
Proceeds from divestitures of proved and unproved properties		1,933			1,933
Additions to other property and equipment		(315)	(364)		(679)
Other investing activities		92	108		200
Cash used in investing activities		(3,476)	(256)		(3,732)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		6,725	319		7,044
Payments on credit facilities borrowings		(7,247)	(168)		(7,415)
Proceeds from issuance of preferred stock, net of offering costs	2,562				2,562
Cash paid to purchase debt	(1,334)				(1,334)
Other financing activities	(128)	324	(5)		191
Intercompany advances, net	(1,100)	1,108	(8)		
Cash provided by financing activities		910	138		1,048
Net increase (decrease) in cash and cash equivalents		308	(14)		294
Cash and cash equivalents, beginning of period		293	14		307
Cash and cash equivalents, end of period	$	$ 601	$	$	$ 601

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

12. Recently Issued and Proposed Accounting Standards

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

In May 2011, the FASB issued guidance which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards (IFRS). This new guidance changes some fair value measurement principles and disclosure requirements. We are evaluating the impact of this guidance which will be adopted effective January 1, 2012.

In 2010, the FASB 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 Period. 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 July 11, 2011, we agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment will be made in three equal $50 million promissory notes, the first of which was issued on July 11, 2011, with the remaining notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy s common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. Under certain circumstances following the second anniversary of the issuance of a note, Clean Energy can force conversion of the debt. The entire principal balance of each note is due and payable seven years following the issuance. Clean Energy will use our $150 million investment to accelerate its build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S.

On July 11, 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The investment over the next two years will fund construction of a nonfood biomass-based green gasoline plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and waste cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. The first $35 million tranche of our investment was funded on July 11, 2011 and the remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached over the next two years. The full investment will represent 50% of Sundrop Fuels equity on a fully diluted basis.

Our investments in Clean Energy Fuels Corp. and Sundrop Fuels, Inc. are held by Chesapeake NG Ventures Corporation (CNGV), a venture capital fund we recently created to identify and invest in companies and technologies that will replace the use of gasoline and diesel derived primarily from imported oil with domestic oil, natural gas and natural gas-to-liquids (GTL) fuels.

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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 and six months ended June 30, 2011 (the Current Quarter and the Current Period) and the three and six months ended June 30, 2010 (the Prior Quarter and the Prior Period):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net Production:				
Natural gas (bcf)	234.3	227.2	477.7	436.8
Oil (mmbbl)[(a)]	7.2	4.4	13.2	8.3
Natural gas equivalent (bcfe)[(b)]	277.5	253.8	557.1	486.6
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 764	$ 733	$ 1,552	$ 1,676
Natural gas derivatives realized gains (losses)	452	552	958	931
Natural gas derivatives unrealized gains (losses)	(115)	(195)	(665)	219
Total natural gas sales	1,101	1,090	1,845	2,826
Oil sales[(a)]	514	251	913	493
Oil derivatives realized gains (losses)	(45)	21	(62)	41
Oil derivatives unrealized gains (losses)	222	(201)	(410)	(301)
Total oil sales	691	71	441	233
Total natural gas and oil sales	$ 1,792	$ 1,161	$ 2,286	$ 3,059
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 3.26	$ 3.23	$ 3.25	$ 3.84
Oil ($ per bbl)[(a)]	$ 71.46	$ 56.58	$ 69.00	$ 59.38
Natural gas equivalent ($ per mcfe)	$ 4.61	$ 3.88	$ 4.43	$ 4.46
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 5.19	$ 5.66	$ 5.25	$ 5.97
Oil ($ per bbl)[(a)]	$ 65.23	$ 61.43	$ 64.30	$ 64.35
Natural gas equivalent ($ per mcfe)	$ 6.07	$ 6.14	$ 6.03	$ 6.46
Other Operating Income[(c)] ($ in millions):				
Marketing, gathering and compression net margin	$ 38	$ 30	$ 69	$ 59
Service operations net margin	$ 30	$ 5	$ 54	$ 12
Other Operating Income[(c)] ($ per mcfe):				
Marketing, gathering and compression net margin	$ 0.14	$ 0.12	$ 0.12	$ 0.12
Service operations net margin	$ 0.11	$ 0.02	$ 0.10	$ 0.03
Expenses ($ per mcfe):				
Production expenses	$ 0.94	$ 0.84	$ 0.90	$ 0.86
Production taxes	$ 0.17	$ 0.15	$ 0.16	$ 0.18
General and administrative expenses	$ 0.46	$ 0.41	$ 0.46	$ 0.44
Natural gas and oil depreciation, depletion and amortization	$ 1.32	$ 1.34	$ 1.30	$ 1.33
Depreciation and amortization of other assets	$ 0.23	$ 0.21	$ 0.24	$ 0.21

Interest expense[(d)]	$	0.07	$	0.13	$	0.04	$	0.18

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	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Interest Expense (Income) ($ in millions):				
Interest expense	$ 6	$ 35	$ 15	$ 90
Interest rate derivatives realized (gains) losses	13	(2)	6	(4)
Interest rate derivatives unrealized (gains) losses	6	(49)	12	(77)
Total interest expense (income)	$ 25	$ (16)	$ 33	$ 9
Net Wells Drilled	290	270	584	513
Net Producing Wells as of the End of the Period	21,912	22,216	21,912	22,216

(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 45,400 producing natural gas and oil wells that are currently producing approximately 3.2 bcfe per day, net to our interest, 84% 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 Bakken/Three Forks in the Williston Basin and the Utica Shale in Ohio and Pennsylvania. 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 Period with 16.454 tcfe, a decrease of 642 bcfe, or 4%. On March 31, 2011, Chesapeake closed the sale of its upstream and midstream assets in the Fayetteville Shale, as described below under *Steps Taken to Implement Our Strategy*. The sale included approximately 2.4 tcfe of proved reserves. Excluding this sale, Chesapeake s proved reserves would have been approximately 18.9 tcfe at June 30, 2011, an increase of 1.8 tcfe, or 10%, over the 2010 year-end proved reserves. The Current Period s proved reserve movement included 557 bcfe of production, 2.507 tcfe of extensions, 145 bcfe of positive performance revisions and 5 bcfe of downward revisions resulting from a decrease in the twelve-month trailing average natural gas prices between December 31, 2010 and June 30, 2011. During the Current Period, we acquired 28 bcfe of estimated proved reserves and divested 2.760 tcfe of estimated proved reserves.

During the Current Period, Chesapeake continued the industry s most active drilling program, drilling 759 gross (480 net) operated wells and participated in another 708 gross (104 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 Period, we invested $2.707 billion in operated wells (using an average of 160 operated rigs) and $720 million in non-operated wells (using an average of 109 non-operated rigs) for total drilling, completing and equipping costs of $3.427 billion, net of drilling and completion carries of $1.129 billion.

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Our total Current Quarter production of 277.5 bcfe consisted of 234.3 bcf of natural gas (84% on a natural gas equivalent basis) and 7.2 mmbbls of oil and natural gas liquids (16% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 3.049 bcfe, an increase of 260 mmcfe, or 9%, over the 2.789 bcfe produced per day in the Prior Quarter.

Our total Current Period production of 557.1 bcfe consisted of 477.7 bcf of natural gas (86% on a natural gas equivalent basis) and 13.2 mmbbls of oil and natural gas liquids (14% on a natural gas equivalent basis). Daily production for the Current Period averaged 3.078 bcfe, an increase of 390 mmcfe, or 15%, over the 2.688 bcfe produced per day in the Prior Period.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (14.5 million net acres) and 3-D seismic (29.4 million acres) in the U.S. We have also accumulated the largest inventory of U.S. natural gas shale play leasehold (2.5 million net acres) and now own a leading position in 12 of what we believe are the top 15 unconventional liquids-rich plays in the U.S. We are currently using 166 operated drilling rigs to further develop our inventory of approximately 38,400 net drillsites.

Our Strategy

Our business strategy is to create value for investors by developing unconventional resource plays onshore in the U.S. We do so by growing production and proved reserves 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 entering into joint venture arrangements.

Increase Liquids Production. In recognition of the value gap between oil and natural gas prices, since 2009 Chesapeake has directed a significant and increasing 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 a leasehold position of approximately 5.5 million net acres and established production in multiple unconventional liquids-rich plays. Our production of oil and natural gas liquids averaged 73,149 barrels (bbls) per day during the Current Period, a 60% increase over the average for the Prior Period 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 and 250,000 bbls per day, or 30%-35% of our production, by year-end 2015.

Debt Reduction and Production Growth. Our strategic and financial plan for 2011-2012, announced on January 6, 2011 as our 25/25 Plan , outlined a 25% reduction in our outstanding long-term debt while growing net natural gas and oil production by 25% during these two years. On July 28, 2011, we announced that we have increased our production forecast and now anticipate delivering approximately 30% production growth for the two-year period ending December 31, 2012. We expect to achieve our goal of reducing 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+.

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. 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. We have focused our service company asset investments where we believe we can achieve outsized margins or where we cannot procure enough of a given service at a reasonable price. As a result, we utilize our service company operations as a financial and operational hedge against oilfield service inflation.

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 cost savings, less turnover among operating teams, an alignment of interests, operational synergies, greater access to 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.

Transform U.S. Transportation Fuels Market and Increase Demand for U.S. Natural Gas and Liquids. In an effort to decrease U.S. dependence on foreign oil imports and increase demand for U.S. natural gas and liquids production, on July 11, 2011, we announced our plan to create a venture capital fund, Chesapeake NG Ventures Corporation (CNGV), dedicated to identifying and investing in companies and technologies that have the potential to reduce the use of gasoline and diesel derived primarily from imported oil with domestic oil, natural gas and natural gas-to-liquids fuels. We believe this plan, if successful, will benefit our industry and will also lower energy costs to ourselves and American consumers, enhance national security, stimulate economic growth, create new high-paying jobs and improve the environment.

To fund our commitment, we intend to redirect approximately 1-2% of our forecasted annual drilling budget away from efforts to increase natural gas supply toward projects that instead are designed to stimulate increased natural gas demand. Over the next 10 years, we anticipate investing at least $1.0 billion in CNGV initiatives seeking breakthroughs in scalable, green energy technologies.

Steps Taken to Implement Our Strategy

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, net production at closing of approximately 415 mcfe per day and midstream assets consisting of approximately 420 miles of pipeline. As part of the transaction, we agreed to provide technical and business services for up to one year for BHP Billiton s Fayetteville properties for an agreed-upon fee. We used a portion of the funds we received from the Fayetteville transaction to purchase outstanding debt as described below.

Purchases of Senior Debt. In May 2011, we completed tender offers to purchase $1.373 billion in aggregate principal amount of certain of our senior notes and $531 million in aggregate principal amount of certain of our contingent convertible senior notes. These tender offers were part of our plan to reduce the amount of our outstanding indebtedness by 25% in the two-year period ending December 31, 2012. 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 in aggregate principal amount of contingent convertible senior notes we purchased in privately negotiated transactions during the Current Period, we have retired an aggregate principal amount of $2.044 billion of senior notes and contingent convertible senior notes in 2011.

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Joint Ventures. In February 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 Sand 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 2013. CNOOC 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 June 30, 2011:

Primary Play	Joint Venture Partner	Joint Venture Date	Carries Remaining ($ in millions)
Marcellus	Statoil	November 2008	$ 869
Barnett	Total	January 2010	611
Eagle Ford	CNOOC	November 2010	731
Niobrara	CNOOC	February 2011	637
			$ 2,848

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 Period and the Prior Period, our drilling and completion costs included the benefit of approximately $1.129 billion and $534 million, respectively, of drilling and completion carries. Our drilling and completion costs for the second half of 2011 through 2013 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 Period, as part of our joint venture agreements with CNOOC, Total, Statoil and Plains Exploration & Production Company, we sold interests in additional leasehold in the Niobrara, Eagle Ford and Pearsall, Barnett, Marcellus and Haynesville and Bossier Shale plays for proceeds of approximately $345 million that had an estimated original cost to us of $230 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). In May 2011, we monetized certain of our producing assets in the Mid-Continent through a ten-year VPP for proceeds of approximately $850 million. The transaction included approximately 180 bcfe of proved reserves and approximately 80 mmcfe per day of 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. This transaction was our ninth VPP. The cash proceeds for this transaction will be reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Bronco Drilling Acquisition. As an extension of our vertical integration strategy, in June 2011 we acquired Bronco Drilling Company, Inc. (Nasdaq/GS:BRNC) through a tender offer for all of the outstanding stock of Bronco. We paid $11.00 per share for each outstanding share of Bronco stock for an aggregate purchase price of approximately $339 million. The acquisition included 22 high-quality drilling rigs primarily operating in the Williston and Anadarko basins.

Frac Tech Ownership Change. Through our investment in the holding company of Frac Tech Services, LLC, we have a 30% equity interest in the fourth largest onshore pressure pumping and well stimulation company in the U.S. On May 6, 2011, there was a change in controlling ownership of FTI s predecessor, Frac Tech Holdings, L.L.C. During the Current Quarter, we also received a cash distribution of approximately $206 million, increased our equity ownership from 26% to 30% and entered into a Master Frac Services Agreement that obligates us to use certain services of FTI through 2014.

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CNGV Investments. On July 11, 2011, CNGV, our venture capital fund described above, made its first two investments. We agreed to invest $150 million in newly issued convertible promissory notes of Clean Energy Fuels Corp. (Nasdaq:CLNE), based in Seal Beach, California. The investment will be made in three equal $50 million promissory notes, the first of which was issued on July 11, 2011, with the remaining two notes scheduled to be issued in June 2012 and June 2013. The notes bear interest at the annual rate of 7.5%, payable quarterly, and are convertible at our option into shares of Clean Energy s common stock at a 22.5% conversion premium, resulting in a conversion price of $15.80 per share. Under certain circumstances following the second anniversary of the issuance of a note, Clean Energy can force conversion of the debt. The entire principal balance of each note is due and payable seven years following issuance. Clean Energy will use our $150 million investment to accelerate its build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S.

Also on July 11, 2011, CNGV agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Louisville, Colorado. The investment over the next two years will fund construction of a nonfood biomass-based green gasoline plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and waste cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. The first $35 million tranche of our investment was funded on July 11, 2011 and the remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached over the next two years. The full investment will represent 50% of Sundrop Fuels equity on a fully diluted basis.

Future Steps to Implement Our Strategy

Proposed Royalty Trust Offering. On July 7, 2011, we and Chesapeake Granite Wash Trust (the Trust), a newly formed Delaware statutory trust, filed a registration statement with the Securities and Exchange Commission (SEC) relating to a proposed public offering of up to approximately $508 million in common units representing beneficial interests in the Trust. Prior to the closing of this offering, we intend to convey certain royalty interests to the Trust in exchange for units representing approximately 50% of the beneficial interest in the Trust and the net proceeds of the Trust s public offering. The royalty interests to be conveyed to the Trust would be in certain natural gas and liquids properties leased by us in the Colony Granite Wash play, located in Washita County, Oklahoma. Pursuant to a development agreement with the Trust, we would be obligated to drill, or cause to be drilled, a specified number of wells, which would also be subject to a royalty interest, by March 31, 2016. One of our wholly owned subsidiaries will grant to the Trust a drilling support lien in our interests in the properties where the development wells will be drilled, in order to secure the estimated amount of the drilling costs for the wells. There can be no assurance that we will complete this transaction, as it is subject to market conditions and other uncertainties, as well as completion of the SEC review process. If we complete this transaction, we intend to use the net proceeds from the offering to repay borrowings under our revolving bank credit facility and for general corporate purposes.

Planned Asset Monetizations. During 2011 and 2012, we expect 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 transactions. Each of these monetizations is subject to market conditions and other factors, and we may not complete any such transactions in the expected time frame or at all.

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 $6.0 - $6.5 billion in each of 2011 and 2012. We anticipate funding our drilling and completion capital expenditures, and other capital expenditures, including leasehold acquisitions, using a combination of cash flow from operations, borrowings from our revolving bank credit facilities and proceeds from asset monetizations.

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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 $2.093 billion in the Current Period compared to $2.978 billion in the Prior Period. 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 the second half of 2011, and including the effect of our open derivatives, closed contracts and previously collected call premiums, as of July 28, 2011, we estimate our average natural gas price will be $5.70 per mcf and average oil price will be $97.09 per bbl for the second half of 2011. Wellhead prices are further reduced from these estimates by the effect of gathering costs and basis and quality differentials and the effect of lower priced NGLs. Our natural gas and oil derivatives as of June 30, 2011 are detailed in Item 3 of Part I of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

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 Period and Prior Period, we received $882 million and $271 million, respectively, for settlements of derivatives which were classified as cash flows from financing activities.

Asset monetizations are part of our business strategy to fund our leasehold acquisition spending and our planned reduction in long-term indebtedness. Current Period property divestiture proceeds of $6.173 billion included $4.310 billion from the sale of our Fayetteville assets, $570 million at the closing of our Niobrara Shale joint venture, $853 million from our ninth VPP transaction, $345 million of joint venture leasehold sales and $95 million from other transactions. Prior Period property divestiture proceeds of $1.933 billion included $800 million in cash at the closing of our Barnett Shale joint venture, $515 million from our sixth and seventh VPP transactions, $320 million of joint venture leasehold sales and $298 million from other transactions. The Fayetteville sale in the Current Period also included proceeds of $352 million for other property and equipment.

Our $4.0 billion corporate revolving bank credit facility, our $600 million midstream revolving bank credit facility (limited to $350 million as of June 30, 2011 by the leverage ratio described below under *Bank Credit Facilities*) 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 $8.343 billion and repaid $10.235 billion in the Current Period, and we borrowed $7.044 billion and repaid $7.415 billion in the Prior Period under 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 Period, in an effort to extend the maturity profile of our outstanding indebtedness at advantageous rates, we issued $1.0 billion in aggregate principal amount 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.

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 Period and the Prior Period. We retain a significant degree of control over the timing of our capital expenditures, which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, 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.

In May 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.

		Principal Amount Purchased ($ in millions)
7.625% senior notes due 2013	$	36
9.5% senior notes due 2015		160
6.25% euro-denominated senior notes due 2017[(a)]		380
6.5% senior notes due 2017		440
6.875% senior notes due 2018		126
7.25% senior notes due 2018		131
6.625% senior notes due 2020		100
Total senior notes		1,373
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
Total contingent convertible senior notes		531
Total	$	1,904

(a) We purchased 256 million in aggregate principal amount of our euro-denominated senior notes which had a value of $380 million based on the exchange rate of $1.4821 to 1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound cross currency swaps for the same principal amount.

During the Current Period, we paid $2.058 billion in cash for the tender offers described above and recorded associated losses of approximately $174 million. The losses included $154 million in cash premiums, $20 million of deferred charges, $160 million of note discounts and $2 million of interest rate hedging losses, offset by $162 million of the equity component of the contingent convertible notes.

During the Current Period, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these repurchases, we recognized a loss of $2 million in the Current Period.

We paid dividends on our common stock of $95 million in both the Current Period and the Prior Period. Dividends paid on our preferred stock increased to $86 million in the Current Period from $11 million in the Prior Period as a result of the issuance of two series of 5.75% Cumulative Convertible Preferred Stock.

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 June 30, 2011, our commodity and interest rate derivative instruments were spread among 14 counterparties. Our multi-counterparty secured hedging facility included 11 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 ($1.071 billion at June 30, 2011) and exploration and production companies which own interests in properties we operate ($1.354 billion at June 30, 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 Period and the Prior Period, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities decreased to $240 million during the Current Period, compared to $3.732 billion during the Prior Period. The majority of the $3.492 billion decrease in cash used in 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 Period and the Prior Period, with acquisitions of unproved properties totaling $2.166 billion and $2.452 billion, respectively. We are projecting substantially reduced leasehold acquisition activity in the remainder of 2011 and in 2012. Exploration and development expenditures increased $1.047 billion to $3.282 billion in the Current Period compared to $2.235 billion in the Prior Period. This increase is due to increased drilling activity. The following table shows our cash used in investing activities during these periods:

	Six Months Ended June 30,	
	2011	2010
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Acquisitions of proved properties	$ (35)	$ (76)
Acquisitions of unproved properties	(2,166)	(2,452)
Exploration and development of natural gas and oil properties	(3,282)	(2,235)
Geological and geophysical costs[(a)]	(113)	(97)
Interest capitalized on unproved properties	(327)	(326)
Proceeds from divestitures of proved and unproved properties	6,173	1,933
Other	(17)	(17)
Total natural gas and oil investing activities	233	(3,270)
Other Investing Activities:		
Additions to other property and equipment	(863)	(679)
Proceeds from (additions to) investments	212	(109)
Proceeds from sales of other assets	526	306
Acquisition of drilling company	(339)	
Other	(9)	20
Total other investing activities	(473)	(462)
Total cash used in investing activities	$ (240)	$ (3,732)

(a) Including related capitalized interest.

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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	June 2016
Borrowing capacity	$ 4,000	$ 600 [c]
Amount outstanding as of June 30, 2011	$ 1,710	$ 104
Letters of credit outstanding as of June 30, 2011	$ 56	$

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

(b) Borrower is Chesapeake Midstream Operating, L.L.C.

(c) The decrease in operating income following the sale of our Haynesville Springridge gathering system and the sale of our Fayetteville gathering system on March 31, 2011 caused the borrowing capacity under the facility to be limited to $350 million as of June 30, 2011. We expect the full borrowing capacity of $600 million to be available by year-end 2011.

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

We use our $4.0 billion syndicated revolving bank credit facility 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 June 30, 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.

Midstream Credit Facility

On June 15, 2011, our midstream credit facility agreement was amended and restated to, among other things, increase the amount we can borrow under the facility from $300 million to $600 million, improve interest rates, extend the maturity by almost a year and favorably restructure covenants. We use the midstream syndicated revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of 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 1.00% to 1.75% per annum or (ii) the Eurodollar rate, which is based on the LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. 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 a result of the sale of our Haynesville Springridge gathering system to Chesapeake Midstream Partners in December 2010, we were subject to a higher leverage ratio during the three quarters ended June 30, 2011. We were in compliance with all covenants under the agreement at June 30, 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 17 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for commodity price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.3 billion under the terms of the facility. As of June 30, 2011, we had hedged under the facility 2.5 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. 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 June 30, 2011, senior notes represented approximately $8.2 billion of our total debt and consisted of the following ($ in millions):

7.625% senior notes due 2013	$	464
9.5% senior notes due 2015		1,265
6.25% euro-denominated senior notes due 2017[(a)]		500
6.5% senior notes due 2017		660
6.875% senior notes due 2018		474
7.25% senior notes due 2018		669
6.625% senior notes due 2020		1,300
6.875% senior notes due 2020		500
6.125% senior notes due 2021		1,000
2.75% contingent convertible senior notes due 2035[(b)]		396
2.5% contingent convertible senior notes due 2037[(b)]		1,168
2.25% contingent convertible senior notes due 2038[(b)]		346
Discount on senior notes[(c)]		(528)
Interest rate derivatives[(d)]		19
	$	8,233

(a) The principal amount shown is based on the exchange rate of $1.4523 to 1.00 as of June 30, 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 second 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 third 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	$ 64.16	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(c) Included in this discount is $476 million at June 30, 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.

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.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at June 30, 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.

Results of Operations Three Months Ended June 30, 2011 vs. June 30, 2010

General. For the Current Quarter, Chesapeake had net income of $510 million, or $0.68 per diluted common share, on total revenues of $3.318 billion. This compares to net income of $255 million, or $0.37 per diluted common share, on total revenues of $2.012 billion during the Prior Quarter.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.792 billion compared to $1.161 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 277.5 bcfe at a weighted average price of $6.07 per mcfe, compared to 253.8 bcfe produced and sold in the Prior Quarter at a weighted average price of $6.14 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of $107 million and ($396) 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 $17 million and increased production resulted in a $145 million increase, for a total increase in revenues of $128 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Quarter to the Current Quarter was primarily generated through the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $5.19, compared to $5.66 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Included in the Current Quarter and the Prior Quarter realized prices 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 June 30, 2011. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $65.23 and $61.43 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 $407 million, or $1.46 per mcfe, in the Current Quarter and a net increase of $573 million, or $2.26 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 $23 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 $7 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 June 30, 2011						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	98.6	3.41			98.6	36%	3.41
Mid-Continent	56.3	3.82	5.0	69.58	86.3	31	6.54
Barnett Shale[c]	32.3	1.41	0.2	37.58	33.5	12	1.61
Marcellus Shale	24.8	3.79	0.2	56.80	26.0	9	4.10
Fayetteville Shale							
Permian and Delaware Basins	9.6	3.64	1.1	89.58	16.2	6	8.29
Eagle Ford Shale	1.0	0.74	0.4	70.60	3.4	1	8.34
Rockies/Williston Basin	0.1	4.22	0.1	87.82	0.7		12.40
Other	11.6	3.23	0.2	69.25	12.8	5	3.81
Total[d]	234.3	3.26	7.2	71.46	277.5	100%	4.61

	Three Months Ended June 30, 2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	52.1	3.38			52.1	21%	3.38
Mid-Continent	58.2	4.02	3.3	53.86	78.1	32	5.28
Barnett Shale[c]	47.4	1.91	0.2	29.24	48.7	19	1.99
Marcellus Shale	11.2	3.94			11.2	4	3.94
Fayetteville Shale	33.7	3.08			33.7	13	3.08
Permian and Delaware Basins	11.5	3.70	0.7	74.33	15.7	6	5.98
Eagle Ford Shale	0.2	6.03	0.1	69.70	0.8		9.96
Rockies/Williston Basin	0.2	3.20			0.2		3.20
Other	12.7	3.19	0.1	69.00	13.3	5	3.59
Total[e]	227.2	3.23	4.4	56.58	253.8	100%	3.88

(a) Includes NGLs.

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

(c) Our Barnett Shale production is concentrated in urban areas where the cost to develop the necessary infrastructure to gather and deliver the natural gas to intrastate pipelines significantly exceeds the cost of similar infrastructure in non-urban areas. As a result, our natural gas price realizations in the Barnett Shale are lower than those in our other operating areas.

(d) The Current Quarter production reflects the sale of all of our Fayetteville Shale assets and various other asset sales, including VPP #7, VPP #8 and VPP #9.

(e) The Prior Quarter production reflects various asset sales including VPP #7.

Our average daily production of 3.049 bcfe for the Current Quarter consisted of 2.575 bcf of natural gas and 79,033 bbls of oil. Our Current Quarter production of 277.5 bcfe consisted of 234.3 bcf of natural gas (84% on a natural gas equivalent basis) and 7.2 mmbbls of oil (16% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 3% and our year-over-year growth rate of oil and NGL (liquids) production was 62%. Our percentage of revenue from liquids in the Current Quarter was 28% 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 $1.404 billion in marketing, gathering and compression sales in the Current Quarter with corresponding marketing, gathering and compression expenses of $1.366 billion, for a net margin before depreciation of $38 million. This compares to sales of $793 million, expenses of $763 million and a net margin before depreciation of $30 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 oilfield services operations. Chesapeake recognized $122 million in service operations revenue in the Current Quarter with corresponding service operations expense of $92 million, for a net margin before depreciation of $30 million. This compares to revenue of $58 million, expenses of $53 million and a net margin before depreciation of $5 million in the Prior Quarter. Service operations margins have increased as service rates increased throughout 2010 and 2011.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $262 million in the Current Quarter and $213 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.94 per mcfe in the Current Quarter compared to $0.84 per mcfe in the Prior Quarter. The per unit expense increase in the Current Quarter was primarily the result of the sale of our Fayetteville Shale producing wells, which were high volume wells with lower per unit costs.

Production Taxes. Production taxes were $46 million in the Current Quarter compared to $37 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.17 per mcfe in the Current Quarter compared to $0.15 per mcfe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. The $9 million increase in production taxes in the Current Quarter is due to an increase in the average realized sales price of natural gas and oil of $0.73 per mcfe (excluding gains or losses on derivatives) and an increase in production of 24 bcfe.

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 $106 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 $0.41 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 $21 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 $102 million and $87 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 $366 million and $340 million during the Current Quarter and the Prior Quarter, respectively. The $26 million increase is primarily the result of a 9% 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 $1.32 and $1.34 in the Current Quarter and in the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $63 million in the Current Quarter and $53 million in the Prior Quarter. Depreciation and amortization of other assets was $0.23 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.

Loss on Sales of Other Property and Equipment. In the Current Quarter, we recorded a $4 million net loss associated with the sales of other property and equipment.

Other Impairments. In the Current Quarter, we recorded a $4 million charge for impairment of certain fixed assets.

Interest Expense (Income). Interest expense was $25 million in the Current Quarter compared to interest income of ($16) million in the Prior Quarter as follows:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
	($ in millions)	
Interest expense on senior notes	$ 164	$ 190
Interest expense on credit facilities	10	12
Realized (gain) loss on interest rate derivatives	13	(2)
Unrealized (gain) loss on interest rate derivatives	6	(49)
Amortization of loan discount and other	8	12
Capitalized interest	(176)	(179)
Total interest expense (income)	$ 25	$ (16)
Average long-term borrowings	$ 9,633	$ 10,806

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.07 per mcfe in the Current Quarter compared to $0.13 per mcfe in the Prior Quarter. The decrease in interest expense per mcfe is due primarily to increased production volumes and a decrease in the aggregate principal amount of our senior notes outstanding.

Earnings from Equity Investees. Earnings from equity investees were $47 million and $27 million in the Current Quarter and the Prior Quarter, respectively. The increase is primarily due to additional earnings from our Frac Tech investment.

Loss on Purchases or Exchanges of Debt. During the Current Quarter, we completed tender offers to purchase $1.373 billion in aggregate principal amount of certain of our senior notes and $531 million in aggregate principal amount of certain of our contingent convertible senior notes. Associated with the tender offers, we recorded losses of approximately $166 million related to the senior notes and $8 million related to the contingent convertible senior notes.

During the Prior Quarter, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in aggregate principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in aggregate principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in aggregate principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Prior Quarter.

Other Income (Expense). Other income (expense) was $2 million in the Current Quarter and ($7) million in the Prior Quarter. The Current Quarter consisted of $2 million of miscellaneous income. The Prior Quarter consisted of $1 million of interest income and ($8) million of miscellaneous expense.

Income Tax Expense. Chesapeake recorded income tax expense of $325 million in the Current Quarter compared to income tax expense of $159 million in the Prior Quarter. Of the $166 million increase in income tax expense recorded in the Current Quarter, $162 million was the result of the increase in net income before income taxes and $4 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.

Results of Operations Six Months Ended June 30, 2011 vs. June 30, 2010

General. For the Current Period, Chesapeake had net income of $347 million, or $0.41 per diluted common share, on total revenues of $4.930 billion. This compares to net income of $993 million, or $1.49 per diluted common share, on total revenues of $4.810 billion during the Prior Period. The Current Period included a net unrealized after-tax mark-to-market loss of $656 million resulting from our natural gas and oil hedging program.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were $2.286 billion compared to $3.059 billion in the Prior Period. In the Current Period, Chesapeake produced and sold 557.1 bcfe at a weighted average price of $6.03 per mcfe, compared to 486.6 bcfe produced and sold in the Prior Period at a weighted average price of $6.46 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($1.075) billion and ($82) million in the Current Period and the Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenue of $235 million and increased production resulted in a $455 million increase, for a total increase in revenues of $220 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Period to the Current Period was primarily generated through the drillbit.

For the Current Period, we realized an average price per mcf of natural gas of $5.25 compared to $5.97 in the Prior Period (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Included in the Current Period and the Prior Period realized prices 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 June 30, 2011. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $64.30 and $64.35 in the Current Period and Prior Period, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $896 million, or $1.60 per mcfe, in the Current Period and a net increase of $972 million, or $2.00 per mcfe, in the Prior Period.

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 Period production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $48 million and $46 million, respectively, and an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $13 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 Period and the Prior Period:

	Six Months Ended June 30, 2011						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	183.9	3.37			183.9	34%	3.37
Mid-Continent	111.9	3.87	9.5	66.75	168.9	30	6.32
Barnett Shale[c]	56.2	1.30	0.5	35.86	59.2	11	1.51
Marcellus Shale	47.6	3.77	0.4	57.15	50.2	9	4.06
Fayetteville Shale	36.0	2.80			36.0	6	2.80
Permian and Delaware Basins	17.7	3.82	2.0	87.01	29.7	5	8.07
Eagle Ford Shale	1.8	3.74	0.5	76.14	4.8	1	9.49
Rockies/Williston Basin	0.3	4.18			0.3		4.18
Other	22.3	3.12	0.3	70.99	24.1	4	3.75
Total[d]	477.7	3.25	13.2	69.00	557.1	100%	4.43

	Six Months Ended June 30, 2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	92.8	3.84			92.8	19%	3.84
Mid-Continent	113.7	4.67	6.2	56.57	150.9	31	5.84
Barnett Shale[c]	97.1	2.74	0.3	32.52	98.9	20	2.79
Marcellus Shale	18.7	4.45			18.7	4	4.45
Fayetteville Shale	64.7	3.51			64.7	13	3.51
Permian and Delaware Basins	23.8	4.48	1.4	75.03	32.2	7	6.57
Eagle Ford Shale	0.3	5.17	0.1	70.48	0.9		9.34
Rockies/Williston Basin	0.3	3.61	0.1	70.18	0.9		7.41
Other	25.4	4.08	0.2	71.56	26.6	6	4.49
Total[e]	436.8	3.84	8.3	59.38	486.6	100%	4.46

(a) Includes NGLs.

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

(c) Our Barnett Shale production is concentrated in urban areas where the cost to develop the necessary infrastructure to gather and deliver the natural gas to intrastate pipelines significantly exceeds the cost of similar infrastructure in non-urban areas. As a result, our natural gas price realizations in the Barnett Shale are lower than those in our other operating areas.

(d) The Current Period production reflects the sale of all of our Fayetteville Shale assets and various other asset sales, including VPP #6, VPP #7, VPP #8 and VPP #9.

(e) The Prior Period production reflects the sale of a 25% joint venture interest in our Barnett Shale assets and various other asset sales, including VPP #6 and VPP #7.

Our average daily production of 3.078 bcfe for the Current Period consisted of 2.639 bcf of natural gas and 73,149 bbls of oil. Our Current Period production of 557.1 bcfe consisted of 477.7 bcf of natural gas (86% on a natural gas equivalent basis) and 13.2 mmbbls of oil (14% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 9% and our year-over-year growth rate of oil and NGL (liquids) production was 60%. Our percentage of revenue from liquids in the Current Period was 25% of realized natural gas and oil revenue compared to 17% in the Prior Period.

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 $2.421 billion in marketing, gathering and compression sales in the Current Period with corresponding marketing, gathering and compression expenses of $2.352 billion, for a net margin before depreciation of $69 million. This compares to sales of $1.637 billion, expenses of $1.578 billion and a net margin before depreciation of $59 million in the Prior Period. In the Current Period, 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 oilfield services operations. Chesapeake recognized $223 million in service operations revenue in the Current Period with corresponding service operations expense of $169 million, for a net margin before depreciation of $54 million. This compares to revenue of $114 million, expenses of $102 million and a net margin before depreciation of $12 million in the Prior Period. Service operations margins have increased as service rates increased throughout 2010 and 2011.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $500 million in the Current Period and $421 million in the Prior Period. On a unit-of-production basis, production expenses were $0.90 per mcfe in the Current Period compared to $0.86 per mcfe in the Prior Period. The per unit expense increase in the Current Period was primarily the result of the sale of our Fayetteville Shale producing wells, which were high volume wells with lower per unit costs.

Production Taxes. Production taxes were $91 million in the Current Period compared to $85 million in the Prior Period. On a unit-of-production basis, production taxes were $0.16 per mcfe in the Current Period compared to $0.18 per mcfe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. The $6 million increase in production taxes in the Current Period is due to an increase in production of 71 bcfe which was partially offset by a decrease in the average realized sales price of natural gas and oil of $0.03 per mcfe (excluding gains or losses on derivatives).

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 $259 million in the Current Period and $215 million in the Prior Period. The increase in the Current Period was the result of the company s continued growth resulting in higher payroll and associated costs. General and administrative expenses were $0.46 and $0.44 per mcfe for the Current Period and Prior Period, respectively. Included in general and administrative expenses is stock-based compensation of $46 million for the Current Period and $42 million for the Prior Period. 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 $211 million and $189 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts 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 $724 million and $647 million during the Current Period and the Prior Period, respectively. The $77 million increase is primarily the result of a 14% increase in production from the Prior Period compared to the Current Period. 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 $1.30 and $1.33 in the Current Period and in the Prior Period, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $131 million in the Current Period and $103 million in the Prior Period. Depreciation and amortization of other assets was $0.24 and $0.21 per mcfe for the Current Period and the Prior Period, respectively. The increase in the Current Period 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 Period, we recorded a $1 million net gain associated with the sales of other property and equipment.

Other Impairments. In the Current Period, we recorded a $4 million charge for impairments of certain fixed assets.

Interest Expense. Interest expense was $33 million in the Current Period compared to $9 million in the Prior Period as follows:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	($ in millions)	
Interest expense on senior notes	$ 342	$ 383
Interest expense on credit facilities	31	24
Capitalized interest	(381)	(340)
Realized (gain) loss on interest rate derivatives	6	(4)
Unrealized (gain) loss on interest rate derivatives	12	(77)
Amortization of loan discount and other	23	23
Total interest expense	$ 33	$ 9
Average long-term borrowings	$ 9,807	$ 10,951

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.04 per mcfe in the Current Period compared to $0.18 per mcfe in the Prior Period. The decrease in interest expense per mcfe is due primarily to increased production volumes, a decrease in the aggregate principal amount of our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased $41 million in the Current Period compared to the Prior Period 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 $72 million and $39 million in the Current Period and the Prior Period, respectively. The increase is primarily due to additional earnings from our Frac Tech investment.

Losses on Purchases or Exchanges of Debt. During the Current Period, we completed tender offers to purchase $1.373 billion in aggregate principal amount of certain of our senior notes and $531 million in aggregate principal amount of certain of our contingent convertible senior notes. Associated with the tender offers we recorded losses of approximately $166 million related to the senior notes and $8 million related to the contingent convertible senior notes. Also, during the Current Period, we repurchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these repurchases, we recognized a loss of $2 million in the Current Period.

During the Prior Period, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in aggregate principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in aggregate principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in aggregate principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Prior Period consisting primarily of the redemption premium and the write-off of the related discount on senior notes and deferred charges.

In the Prior Period, 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 Period.

Other Income (Expense). Other income (expense) was $5 million in the Current Period and ($4) million in the Prior Period. The Current Period consisted of $1 million of interest income and $4 million of miscellaneous income. The Prior Period consisted of $2 million of interest income and ($6) million of miscellaneous income.

Income Tax Expense. Chesapeake recorded income tax expense of $222 million in the Current Period compared to income tax expense of $621 million in the Prior Period. Of the $399 million decrease in income tax expense recorded in the Current Period, $402 million was the result of the decrease in net income before income taxes which was partially offset by a $3 million increase due to an increase in the effective tax rate. Our effective income tax rate was 39% in the Current Period and 38.5% in the Prior Period. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties 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 the following standards which we reviewed to determine the potential impact on our financial statements upon adoption.

In May 2011, the FASB issued guidance which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards (IFRS). This new guidance changes some fair value measurement principles and disclosure requirements. We are evaluating the impact of this guidance which will be adopted effective January 1, 2012.

In 2010, the FASB 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 Period. 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.

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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 drilling activity and drilling and completion capital expenditures, and anticipated asset monetizations, 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 SEC that attempt to advise interested parties of the risks and factors that may affect our business.

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

Natural Gas and Oil Derivatives

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 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.

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.

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As of June 30, 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 June 30, 2011, we had the following open natural gas and oil derivative instruments.

	Volume (bbtu)	Fixed	Weighted Average Price Put (per mmbtu)	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Natural Gas:							
Qualified Swaps:							
Q3 2011	189,238	$ 4.88	$	$	$	Yes	$ 95
Q4 2011	186,075	4.82				Yes	45
2012	5,460	6.17				Yes	8
Non-Qualified Swaps:							
Q3 2011	14,125	6.96				No	36
Q4 2011	16,690	6.10				No	25
2012	101,130	6.14				No	137
Call Options:							
2012	161,077			6.54		No	(18)
2013	415,046			6.44		No	(124)
2014	330,183			6.43		No	(160)
2015	226,446			6.31		No	(159)
2016 2020	392,631			7.93		No	(308)
Put Options:							
Q3 2011	(16,560)		5.42			No	(18)
Q4 2011	(16,560)		5.48			No	(17)
Basis Protection Swaps (Non-Appalachian Basin):							
Q3 2011	19,397				(0.82)	No	(12)
Q4 2011	6,545				(0.82)	No	(4)
2012	50,532				(0.78)	No	(25)
2013 2019	29,349				(0.69)	No	(10)
Basis Protection Swaps (Appalachian Basin):							
Q3 2011	12,403				0.14	No	
Q4 2011	12,324				0.14	No	1
2012 2022	134				0.11	No	
	Total Natural Gas						(508)

	Volume (mbbl)	Fixed	Weighted Average Price Put (per bbl)	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Oil:							
Qualified Swaps:							
Q3 2011	552	$ 98.98		$	$	Yes	$ 1
Q4 2011	552	98.98				Yes	1
2012	1,098	102.05				Yes	2
Call Options[(a)]:							
Q3 2011	2,300			95.81		No	(12)
Q4 2011	2,300			95.81		No	(16)
2012	23,969			84.12		No	(443)
2013	14,564			87.20		No	(319)

2014	8,707			87.72	No	(200)
2015	11,225			92.00	No	(238)
2016 2017	14,424			89.75	No	(324)
Knock-Out Swaps:						
Q3 2011	276	104.75	60.00		No	2
Q4 2011	276	104.75	60.00		No	2
2012	732	109.50	60.00		No	6
Total Oil						(1,538)
Total Natural Gas and Oil						$ (2,046)

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(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 June 30, 2011, we had $590 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:

	June 30, 2011 ($ in millions)
Q3 2011	$ 221
Q4 2011	201
2012	309
2013	26
2014	(229)
2015	99
2016 2022	(37)
Total	$ 590

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 partially 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 Period change in fair value of our natural gas and oil derivatives. Of the $2.0 billion fair value liability as of June 30, 2011, $44 million related to contracts maturing in the next 12 months, of which we expect to transfer approximately $10 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($2.1) billion related to contracts maturing after 12 months. All transactions hedged as of June 30, 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	(72)
Fair value of new contracts when entered into	(126)
Contracts realized or otherwise settled	(474)
Fair value of contracts when closed	(725)
Fair value of contracts outstanding, as of June 30	$ (2,046)

The change in natural gas and oil prices during the Current Period increased the value of our derivative liabilities by $72 million. This loss is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which were in a liability position of $126 million. We settled contracts for $474 million and we closed out contracts that were in an asset position for $725 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, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ in millions)			
Natural gas and oil sales	$ 1,278	$ 984	$ 2,465	$ 2,169
Realized gains (losses) on natural gas and oil derivatives	407	573	896	972
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	99	(378)	(1,093)	(58)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	8	(18)	18	(24)
Total natural gas and oil sales	$ 1,792	$ 1,161	$ 2,286	$ 3,059

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)]	$	$	$ 464	$	$ 1,265	$ 7,013	$ 8,742
Average interest rate			7.63%		9.5%	5.49%	6.18%
Long-term debt variable rate	$	$	$	$	$ 1,710	$ 104	$ 1,814
Average interest rate					1.95%	2.57%	1.98%

(a) This amount does not include the discount included in long-term debt of ($528) million and interest rate derivatives of $19 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.

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Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of June 30, 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.

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.

As of June 30, 2011, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Weighted Average Rate Floating[(a)]	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating:						
Swaps						
Mature 2018 2020	$ 300	6.94%	3 mL plus 424 bp	Yes	$	$ (11)
Mature 2017	$ 250	6.50%	3 mL plus 429 bp	No		(4)
Swaption						
Expire 2011	$ 450	6.79%	3 ml plus 334 bp	No	3	(8)
Floating to Fixed:						
Swaps						
Mature 2014	$ 1,050	2.19%	1 6 mL	No		(33)
					$ 3	$ (56)

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

In addition to the open derivative positions disclosed above, at June 30, 2011 we had $81 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 transferred $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, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	($ in millions)			

Interest expense on senior notes	$ 164	$ 190	$ 342	$ 383
Interest expense on credit facilities	10	12	31	24
Realized (gains) losses on interest rate derivatives	13	(2)	6	(4)
Unrealized (gains) losses on interest rate derivatives	6	(49)	12	(77)
Amortization of loan discount and other	8	12	23	23
Capitalized interest	(176)	(179)	(381)	(340)
Total interest expense (income)	$ 25	$ (16)	$ 33	$ 9

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Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired 256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the condensed consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake 11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as an asset of $7 million at June 30, 2011. The euro-denominated debt in long-term debt has been adjusted to $500 million at June 30, 2011 using an exchange rate of $1.4523 to 1.00.

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 in reports we file or submit 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 management, including our 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 June 30, 2011.

No changes in our internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, our 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 orders for compliance initiated in the 2010 fourth quarter 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 working with the EPA to resolve these matters. We believe that resolution will include monetary sanctions exceeding $100,000 but are unable to estimate the amount of any fines that might be imposed by the EPA.

Following a well control incident in Bradford County, Pennsylvania on April 19, 2011, Chesapeake voluntarily suspended well completion operations in the state and responded to a notice of violation issued by the Pennsylvania Department of Environmental Protection (DEP). With the concurrence of the DEP, we resumed well completion operations in mid-May 2011, and we have provided the DEP information regarding our investigation of the incident and the potential environmental impact of the event. Our investigation identified the origin of the well control incident as occurring within the wellhead, and we conducted wellhead inspections on other wells in the completion phase in the Marcellus Shale and implemented responsive measures. While a small amount of well fluid and rain water was released from the containment area of the well location, the impact to the environment from this release was shown to be minimal and localized. Chesapeake provided the DEP a list of well fluid additives promptly after the incident and also caused the list to be made available to the public. Both Chesapeake and the DEP have conducted extensive surface water and water well testing to confirm the environmental impact. We are unable to predict at this time the amount of any fines or penalties that may result from this incident.

Under a Consent Order and Agreement (COA) dated May 16, 2011 between Chesapeake and the DEP, Chesapeake agreed to pay a fine of $700,000 for allegedly contaminating private water supplies in Bradford County, Pennsylvania and to donate $200,000 to the DEP s well-plugging fund. The DEP determined that Chesapeake failed to properly case and cement certain wells located in seven areas of Bradford County and to prevent the migration of natural gas into sources of fresh water. As part of the COA, Chesapeake agreed to take multiple corrective actions, including creating a plan approved by the DEP that outlines corrective actions for the wells in question; installing pressure gauge equipment; reporting water supply complaints to DEP; and remediating the contaminated water supplies. While the COA notes that Chesapeake disagrees with the DEP s determination of natural gas migration, Chesapeake elected to enter into the COA and improve its well construction practices in an effort to continue its commitment to responsible drilling operations.

Under a second COA, also dated May 16, 2011, Chesapeake agreed to pay a fine of $188,000 in connection with a February 23, 2011 tank fire at a drilling site in Washington County, Pennsylvania. While Chesapeake personnel were testing and collecting fluids from three wells on the drill site, condensate separator tanks at the wells caught fire, injuring three subcontractors working on the site. The DEP conducted an investigation and determined the cause was improper handling and management of condensate. Under the COA, Chesapeake was required to submit to the DEP a condensate management plan for each well site that may produce condensate.

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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.

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]
April 1, 2011 through April 30, 2011	13,796	$ 33.67		
May 1, 2011 through May 31, 2011	60,439	$ 31.26		
June 1, 2011 through June 30, 2011	17,007	$ 29.51		
Total	91,242	$ 31.30		

(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		
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan	8-K	001-13726	10.1.14	6/16/2011		
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
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema Document.						X

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
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

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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: August 9, 2011

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon

Chairman of the Board and

Chief Executive Officer

Date: August 9, 2011

By: /s/ DOMENIC J. DELL OSSO, JR.
Domenic J. Dell Osso, Jr.

Executive Vice President and

Chief Financial Officer

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