CHESAPEAKE ENERGY CORP
Form 10-Q
November 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 September 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 (State or other jurisdiction of incorporation or organization)	**73-1395733** (I.R.S. Employer Identification No.)
6100 North Western Avenue	
Oklahoma City, Oklahoma (Address of principal executive offices)	**73118** (Zip Code)

(405) 848-8000

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant 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 November 2, 2011, there were 659,266,080 shares of our common stock, $0.01 par value, outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2011	December 31, 2010
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 111	$ 102
Accounts receivable	2,737	1,974
Short-term derivative instruments	5	947
Deferred income tax asset	474	139
Other current assets	143	104
Total Current Assets	3,470	3,266
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	39,955	38,952
Unevaluated properties	16,421	14,469
Natural gas gathering systems and treating plants	1,836	1,545
Other property and equipment	4,531	3,726
Total Property and Equipment, at Cost	62,743	58,692
Less: accumulated depreciation, depletion and amortization	(27,605)	(26,314)
Total Property and Equipment, Net	35,138	32,378
OTHER ASSETS:		
Investments	1,166	1,208
Other long-term assets	348	327
Total Other Assets	1,514	1,535
TOTAL ASSETS	$ 40,122	$ 37,179
CURRENT LIABILITIES:		
Accounts payable	$ 2,844	$ 2,069
Short-term derivative instruments	136	15
Accrued interest	106	191
Other current liabilities	3,109	2,215
Total Current Liabilities	6,195	4,490
LONG-TERM LIABILITIES:		
Long-term debt, net	11,789	12,640
Deferred income tax liabilities	3,524	2,384
Long-term derivative instruments	1,502	1,693
Asset retirement obligations	313	301

Other long-term liabilities	501	407
Total Long-Term Liabilities	17,629	17,425
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 and 7,254,515 shares outstanding	3,062	3,065
Common stock, $0.01 par value, 1,000,000,000 shares authorized, 660,852,092 and 655,251,275 shares issued	7	7
Paid-in capital	12,128	12,194
Retained earnings	1,234	190
Accumulated other comprehensive income (loss), net of tax of $65 million and $102 million	(106)	(168)
Less: treasury stock, at cost; 1,338,448 and 1,221,299 common shares	(27)	(24)
Total Stockholders Equity	16,298	15,264
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 40,122	$ 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 September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	($ in millions, except per share data)			
REVENUES:				
Natural gas and oil sales	$ 2,402	$ 1,639	$ 4,688	$ 4,698
Marketing, gathering and compression sales	1,422	883	3,844	2,520
Oilfield services revenue	153	59	376	173
Total Revenues	3,977	2,581	8,908	7,391
OPERATING COSTS:				
Production expenses	282	231	782	652
Production taxes	50	34	140	119
General and administrative expenses	151	125	410	340
Marketing, gathering and compression expenses	1,392	851	3,744	2,429
Oilfield services expense	118	52	287	154
Natural gas and oil depreciation, depletion and amortization	423	378	1,147	1,025
Depreciation and amortization of other assets	75	56	206	159
Losses on sales of other property and equipment	3	17	3	17
Other impairments		20	4	20
Total Operating Costs	2,494	1,764	6,723	4,915
INCOME FROM OPERATIONS	1,483	817	2,185	2,476
OTHER INCOME (EXPENSE):				
Interest expense	(4)	(3)	(37)	(12)
Earnings on investments	28	151	100	190
Losses on purchases or exchanges of debt		(59)	(176)	(130)
Impairment of investments		(16)		(16)
Other income	4	17	9	12
Total Other Income (Expense)	28	90	(104)	44
INCOME BEFORE INCOME TAXES	1,511	907	2,081	2,520
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	(1)	(1)	11	4
Deferred income taxes	590	350	801	966
Total Income Tax Expense	589	349	812	970
NET INCOME	922	558	1,269	1,550

Preferred stock dividends	(43)	(43)	(128)	(68)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$ 879	$ 515	$ 1,141	$ 1,482
EARNINGS PER COMMON SHARE:				
Basic	$ 1.38	$ 0.81	$ 1.79	$ 2.35
Diluted	$ 1.23	$ 0.75	$ 1.69	$ 2.24
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.0875	$ 0.075	$ 0.25	$ 0.225
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	638	632	636	631
Diluted	753	744	752	692

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	($ in millions)			
Net income	$ 922	$ 558	$ 1,269	$ 1,550
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $44 million, $39 million, $133 million and $153 million	72	65	218	251
Reclassification of gain on settled contracts, net of income taxes of ($49) million, ($68) million, ($88) million and ($203) million	(80)	(112)	(144)	(333)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $2 million, ($2) million, ($5) million and $8 million	3	(3)	(8)	12
Unrealized gain (loss) on marketable securities, net of income taxes of ($1) million, $1 million, ($2) million and ($4) million	(1)	1	(4)	(7)
Comprehensive income	$ 916	$ 509	$ 1,331	$ 1,473

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 1,269	$ 1,550
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,353	1,184
Deferred income tax expense	801	966
Unrealized (gains) losses on derivatives	456	(45)
Stock-based compensation	119	111
Accretion of discount on contingent convertible notes		58
Gains on investments	(19)	(120)
Losses on purchases or exchanges of debt	5	29
Losses on sales of other property and equipment	3	17
Impairment of investments		16
Other impairments	4	20
Other	7	12
Changes in assets and liabilities	(274)	173
Cash provided by operating activities	3,724	3,971
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs on proved and unproved properties	(5,345)	(3,718)
Acquisitions of proved and unproved properties	(3,773)	(4,217)
Proceeds from divestitures of proved and unproved properties	6,357	3,107
Additions to other property and equipment	(1,416)	(968)
Proceeds from sales of other assets	682	328
Proceeds from (additions to) investments	126	(113)
Deposits on acquisitions		(95)
Acquisition of drilling company	(339)	
Other	(7)	11
Cash used in investing activities	(3,715)	(5,665)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	11,914	10,458
Payments on credit facilities borrowings	(12,057)	(9,863)
Proceeds from issuance of senior notes, net of offering costs	977	1,967
Proceeds from issuance of preferred stock, net of offering costs		2,562
Cash paid to purchase debt	(2,015)	(3,434)
Cash paid for common stock dividends	(151)	(142)
Cash paid for preferred stock dividends	(128)	(49)
Cash received on financing derivatives	1,085	436
Net increase in outstanding payments in excess of cash balance	489	116
Other	(114)	(55)

Cash provided by financing activities				1,996
Net increase in cash and cash equivalents		9		302
Cash and cash equivalents, beginning of period		102		307
Cash and cash equivalents, end of period	$	111	$	609

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30, 2011	2010
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF NET CASH PAYMENTS (REFUNDS) FOR:		
Interest, net of capitalized interest	$ 18	$ 103
Income taxes, net of refunds received	$ (25)	$ (291)

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

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

For the nine months ended September 30, 2011 and 2010, natural gas and oil properties were adjusted by $148 million and $116 million, respectively, as a result of an increase in accrued costs.

For the nine months ended September 30, 2011 and 2010, other property and equipment were adjusted by $90 million and ($6) million, respectively, as a result of an increase (decrease) in accrued costs.

As of September 30, 2011 and 2010, we had recorded $173 million and $317 million, respectively, as a result of various accrued liabilities related to the purchase of proved and unproved properties and other assets.

During the nine months ended September 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 September 30, 2011, 3,000 shares of our outstanding 5.75% Cumulative Convertible Non-Voting Preferred Stock were converted into 111,111 shares of common stock pursuant to the holder s conversion rights.

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)

	Nine Months Ended September 30, 2011	Nine Months Ended September 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 3,000 and 5,000 shares of preferred stock for common stock	(3)	(1)
Balance, end of period	3,062	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 111,111 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	120	172
Purchase of contingent convertible notes	(123)	
Exchange of convertible notes for 0 and 298,500 shares of common stock		8
Exchange of 3,000 and 5,000 shares of preferred stock for common stock	3	1
Exercise of stock options	2	2
Offering expenses		(39)
Reduction in tax benefit from stock-based compensation	(5)	(13)
Dividends on common stock	(48)	(95)
Dividends on preferred stock	(15)	(44)
Balance, end of period	12,128	12,138
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	190	(1,261)
Net income	1,269	1,550
Cumulative effect of accounting change, net of income taxes of $89 million		(142)
Dividends on common stock	(112)	(47)
Dividends on preferred stock	(113)	(43)
Balance, end of period	1,234	57
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(168)	102
Hedging activity	66	(70)

Investment activity	(4)	(7)
Balance, end of period	(106)	25
TREASURY STOCK COMMON:		
Balance, beginning of period	(24)	(15)
Purchase of 191,153 and 179,140 shares for company benefit plans	(5)	(4)
Release of 74,004 and 6,963 shares for company benefit plans	2	
Balance, end of period	(27)	(19)
NONCONTROLLING INTEREST:		
Balance, beginning of period		897
Deconsolidation of investment in Chesapeake Midstream Partners		(897)
Balance, end of period		
TOTAL STOCKHOLDERS EQUITY	$ 16,298	$ 15,273

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 nine months ended September 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 nine months ended September 30, 2011 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 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 September 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Knockout Swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than a certain pre-determined knockout price.

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

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

The estimated fair values of our natural gas and oil derivative instruments as of September 30, 2011 and December 31, 2010 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2011		December 31, 2010	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (bbtu):				
Fixed-price swaps		$	1,035,134	$ 1,307
Call options	1,499,285	(554)	1,477,742	(701)
Put options	(16,560)	(27)	(51,220)	(59)
Basis protection swaps	98,885	(44)	173,691	(55)
Total natural gas	1,581,610	(625)	2,635,347	492
Oil (mbbl):				
Fixed-price swaps	2,808	11	4,385	(31)
Call options	89,243	(946)	64,226	(1,129)
Fixed-price knockout swaps	1,008	20	1,827	19
Total oil	93,059	(915)	70,438	(1,141)
Total estimated fair value		$ (1,540)		$ (649)

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 currently reported in the condensed consolidated statements of operations within natural gas and oil sales.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ in millions)			
Natural gas and oil sales	$ 1,427	$ 1,074	$ 3,892	$ 3,243
Gains (losses) on natural gas and oil derivatives	980	560	783	1,475
Gains (losses) on ineffectiveness of cash flow hedges	(5)	5	13	(20)
Total natural gas and oil sales	$ 2,402	$ 1,639	$ 4,688	$ 4,698

Based upon the market prices at September 30, 2011, we expect to transfer approximately $87 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 September 30, 2011 are expected to mature by December 31, 2022.

We have a multi-counterparty secured hedging facility with 18 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 $17.5 billion under the terms of the facility. As of September 30, 2011, we had hedged under the facility 2.0 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.

To mitigate our exposure to the fluctuation in prices of diesel fuel, which is used in our exploration and development activities, we have entered into diesel swaps from October 2011 to December 2012 for a total of 60 million gallons with an average fixed price of $2.99 per gallon. Chesapeake pays the fixed price and receives a floating price. The fair value of these swaps as of September 30, 2011 was a liability of $16 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 September 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.

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

	September 30, 2011		December 31, 2010	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 1,050	$ (46)	$ 1,900	$ (54)
Call options			250	(2)
Swaptions	300		500	(13)
Total	$ 1,350	$ (46)	$ 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 below. 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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ in millions)			
Interest expense on senior notes	$ 152	$ 167	$ 494	$ 550
Interest expense on credit facilities	18	18	49	42
(Gains) losses on interest rate derivatives			19	(81)
Amortization of loan discount and other	8	3	30	26
Capitalized interest	(174)	(185)	(555)	(525)
Total interest expense	$ 4	$ 3	$ 37	$ 12

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 nine 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. 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 a liability of $31 million at September 30, 2011. The euro-denominated debt in long-term debt has been adjusted to $463 million at September 30, 2011 using an exchange rate of $1.3449 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.

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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 September 30, 2011 and December 31, 2010 on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value September 30, 2011	Fair Value December 31, 2010
		($ in millions)	
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$	$ 307
Commodity contracts	Long-term derivative instruments		12
Total			319
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	73	921
Commodity contracts	Long-term derivative instruments	36	229
Total		109	1,150
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments		(59)
Interest rate contracts	Long-term derivative instruments		(25)
Foreign currency contracts	Long-term derivative instruments	(31)	(43)
Total		(31)	(127)
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(204)	(222)
Commodity contracts	Long-term derivative instruments	(1,461)	(1,837)
Interest rate contracts	Short-term derivative instruments		(15)
Interest rate contracts	Long-term derivative instruments	(46)	(29)
Total		(1,711)	(2,103)
Total derivative instruments		$ (1,633)	$ (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 statements of operations for instruments designated as fair value derivatives:

	$000	$000	$000	$000	$000
		Three Months Ended September 30,		**Nine Months Ended September 30,**	
Fair Value Derivatives	**Location of Gain (Loss)**	**2011**	**2010**	**2011**	**2010**
		($ in millions)			
Interest rate contracts	Interest expense[(a)]	$ 3	$ 3	$ 14	$ 16

(a) Interest expense on items hedged during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period was $2 million, $0, $23 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:

		Three Months Ended September 30,		**Nine Months Ended September 30,**	
Cash Flow Derivatives	**Location of Gain (Loss)**	**2011**	**2010**	**2011**	**2010**
		($ in millions)			
Gain (Loss) Recognized in AOCI (Effective Portion)					
Commodity contracts	AOCI	$ 122	$ 94	$ 372	$ 458
Foreign currency contracts	AOCI	(1)	5	(34)	(34)
		$ 121	$ 99	$ 338	$ 424
Gain (Loss) Reclassified from AOCI (Effective Portion)					
Commodity contracts	Natural gas and oil sales	$ 129	$ 179	$ 270	$ 535
Foreign currency contracts	Interest expense			(18)	
Foreign currency contracts	Loss on purchase of debt			(20)	

		$ 129	$ 179	$ 232	$ 535
Gain (Loss) Recognized in Income					
Commodity contracts					
Ineffective portion	Natural gas and oil sales	$ (5)	$ 5	$ 13	$ (20)
Amount initially excluded from effectiveness testing	Natural gas and oil sales		(3)	22	(75)
		$ (5)	$ 2	$ 35	$ (95)

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(Unaudited)

Non-Qualifying Derivatives

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

		Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative Contracts	**Location of Gain (Loss)**	**2011**	**2010**	**2011**	**2010**
		($ in millions)			
Commodity contracts	Natural gas and oil sales	$ 851	$ 384	$ 491	$ 1,015
Interest rate contracts	Interest expense	(3)	(3)	(14)	65
	Total	$ 848	$ 381	$ 477	$ 1,080

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 September 30, 2011, our commodity and interest rate derivative instruments were spread among 12 counterparties. Additionally, our multi-counterparty secured hedging facility described above includes 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 natural gas, oil and natural gas liquids 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. On September 2, 2010, the court denied the defendants motion to dismiss, and on August 1, 2011, the plaintiffs filed a motion for class certification. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action is stayed pursuant to stipulation. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. Chesapeake is named as a nominal defendant in both derivative actions.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging, among other things, breaches of fiduciary duties relating to the 2008 compensation of the company s CEO and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake s motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition

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for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011. On November 1, 2011, the company entered into a Stipulation and Agreement of Settlement (the Stipulation) setting forth the terms of a proposed settlement between the parties in this derivative action, as well as in an inspection demand case requesting books and records relating to the company s December 2008 employment agreement with its CEO. The inspection demand case, currently on appeal at the Oklahoma Court of Civil Appeals, was filed initially on March 26, 2009 in the District Court of Oklahoma County, Oklahoma, and the plaintiff s petition for writ of mandate to compel inspection was denied on September 2, 2009. On November 1, 2011, the District Court of Oklahoma County, Oklahoma entered an order preliminarily approving settlement of the two cases in accordance with the Stipulation filed November 1, 2011. The settlement, if approved by the court, will not have a material effect on the company s consolidated financial position, results of operations or cash flows, and the litigation will be dismissed with prejudice against all defendants. The order also approved distribution of a notice of settlement to Chesapeake shareholders and set a hearing date to consider final approval of the settlement for January 30, 2012. The appeals of both the consolidated derivative case and the inspection demand case have been stayed pending court approval of the settlement.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the company s current and former directors, two shareholders have alleged that the company s directors have waived the demand requirement for derivative actions or wrongfully refused their demands that the board take certain actions related to executive compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the company.

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

The company records an associated liability when a loss is probable and the amount is reasonably estimable. Based on management s current assessment, we are of the opinion that no pending or threatened lawsuit or dispute incidental to the company s business operations is likely to have a material adverse effect on its 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. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability and is not aware of any potential material environmental issues or claims at September 30, 2011. There is, however, an enforcement action pending against us related to compliance with Clean Water Act permitting requirements in West Virginia, and the Pennsylvania Department of Environmental Protection has issued compliance orders with respect to alleged violations of the Pennsylvania Clean Streams Law related to the construction of a well pad and erosion and sediment control associated with another pad site. The Pennsylvania Department of Environmental Protection has also issued a notice of violation alleging violations of the state s Oil and Gas Act, Clean Streams Law and Solid Waste Management Act relating to a well control incident. While we

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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anticipate these actions will result in monetary sanctions, we do not expect that they will have a material adverse effect on the company s consolidated financial position, results of operations or cash flows.

Rig Leases

In a series of transactions since 2006, our drilling subsidiaries have sold 93 drilling rigs (net of one repurchased rig) and related equipment for $802 million and entered into master lease agreements 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 oilfield services 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 September 30, 2011, the minimum aggregate undiscounted future rig lease payments were approximately $481 million.

Compressor Leases

Through various transactions since 2007, our compression subsidiary has sold 2,542 compressors (net of six repurchased units), a significant portion of its compressor fleet, for $635 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 September 30, 2011, the minimum aggregate undiscounted future compressor lease payments were approximately $496 million.

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 to move certain of 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. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying condensed consolidated balance sheets.

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

	September 30, 2011 ($ in millions)
2011	$ 233
2012	1,026
2013	1,170
2014	1,168
2015	1,213

2016 - 2099		6,878
Total	$	11,688

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(Unaudited)

Drilling Contracts

Chesapeake has contracts with various drilling contractors to lease approximately 64 rigs with terms ranging from four months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2011, the aggregate undiscounted minimum future drilling rig commitment was approximately $494 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 certain of our partners (Statoil, Total and CNOOC), we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas for certain designated time periods.

Other Obligations

In April 2011, we entered into a master frac services agreement with Frac Tech Services, LLC, under which we agreed to a structured fee for the exclusive use of a portion of Frac Tech s pressure pumping fleets through December 31, 2014.

In July 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 is being 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. See Note 9 for further discussion of this investment.

In July 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 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. See Note 9 for further discussion of this investment.

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

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 September 30, 2011:			
Basic EPS	$ 879	638	$ 1.38
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		8	
Outstanding stock options		1	
Diluted EPS	$ 922	753	$ 1.23
Three Months Ended September 30, 2010:			
Basic EPS	$ 515	632	$ 0.81
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	40	
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		4	
Outstanding stock options		1	

Diluted EPS	$	558	744	$ 0.75

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	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Nine Months Ended September 30, 2011:			
Basic EPS	$ 1,141	636	$ 1.79
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	64	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	47	39	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	8	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	9	6	
Unvested restricted stock		9	
Outstanding stock options		1	
Diluted EPS	$ 1,269	752	$ 1.69
Nine Months Ended September 30, 2010:			
Basic EPS	$ 1,482	631	$ 2.35
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	28	24	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	23	20	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	8	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	9	6	
Unvested restricted stock		5	
Outstanding stock options		1	
Diluted EPS	$ 1,550	692	$ 2.24

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(Unaudited)

5. Stockholders Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares issued for the nine months ended September 30, 2011 and 2010:

	2011	2010
	(in thousands)	
Shares issued at January 1	655,251	648,549
Restricted stock issuances (net of forfeitures)	5,096	6,108
Stock option exercises	394	354
Convertible note exchanges		299
Preferred stock conversions/exchanges	111	21
Shares issued at September 30	660,852	655,331

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 nine months ended September 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	1,500	1,100	2,559	2,096	
Conversion of preferred into common stock	(3)				
Shares outstanding at September 30, 2011	1,497	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 September 30, 2010	1,500	1,100	2,559	2,096	

In the Current Period, 3,000 shares of our outstanding 5.75% Cumulative Convertible Non-Voting Preferred Stock were converted into 111,111 shares of common stock pursuant to the holder s conversion rights.

In the Prior Period, 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.

In the Prior Period, 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.

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(Unaudited)

In the Prior Period, 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.

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 5.00% 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 program consists of restricted stock, and prior to 2006 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 of the equity instruments 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 oilfield services 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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ in millions)			
Natural gas and oil properties	$ 30	$ 30	$ 90	$ 95
General and administrative expenses	24	21	71	63
Production expenses	8	9	26	27
Marketing, gathering and compression expenses	5	5	14	13
Oilfield services expense	3	2	8	7
Total	$ 70	$ 67	$ 209	$ 205

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.

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(Unaudited)

A summary of the changes in unvested shares of restricted stock for the nine months ended September 30, 2011 is presented below.

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2011	21,375	$ 28.68
Granted	9,321	$ 28.44
Vested	(10,033)	$ 31.88
Forfeited	(749)	$ 27.37
Unvested shares as of September 30, 2011	19,914	$ 27.01

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $289 million based on the stock price at the time of vesting.

As of September 30, 2011, there was $397 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 three 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, the Prior Quarter, the Current Period and the Prior Period, we recognized reductions in tax benefits related to restricted stock of $7 million, $14 million, $8 million and $15 million, respectively, which were recorded as adjustments to additional paid-in-capital and deferred income taxes.

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 nine months ended September 30, 2011:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a] ($ in millions)
Outstanding at January 1, 2011	1,808	$ 8.90	2.03	$ 31
Exercised	(483)	$ 6.88		
Outstanding and exercisable at September 30, 2011	1,325	$ 9.64	1.53	$ 21

(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.

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During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of a nominal amount, $1 million, $3 million and $2 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

6. Debt

Our long-term debt consisted of the following at September 30, 2011 and December 31, 2010:

	September 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]	463	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	3,236	3,612
Midstream revolving bank credit facility	327	94
Discount on senior notes[c]	(509)	(777)
Interest rate derivatives[d]	30	9
Total long-term debt	$ 11,789	$ 12,640

(a) The principal amount shown is based on the exchange rate of $1.3449 to 1.00 and $1.3269 to 1.00 as of September 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 third 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 fourth 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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(Unaudited)

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 $460 million at September 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 and, beginning in the 2011 fourth quarter, Chesapeake Oilfield Services, L.L.C. and its subsidiaries (see Note 13 for this subsequent event). 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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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 which is described in Note 8.

	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 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 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 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

During the Prior Period, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. Associated with the redemption, we recognized a loss of $19 million in the Prior Period.

During the Prior Period, we filed a shelf registration statement on Form S-3 with the SEC for the offering from time to time of debt securities.

During the Prior Period, we completed a public offering of $2.0 billion aggregate principal amount of senior notes for net proceeds of approximately $1.967 billion. The offering consisted of $600 million of 6.875% Senior Notes due 2018 and $1.4 billion of 6.625% Senior Notes due 2020. Both series were priced at par.

During the Prior Period, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 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.

Bank Credit Facilities

As of September 30, 2011, we utilized two revolving bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Corporate Credit Facility[(a)]	Corporate Credit 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 September 30, 2011	$ 3,236	$ 327
Letters of credit outstanding as of September 30, 2011	$ 60	$

(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 in December 2010 and the sale of our Fayetteville gathering system in March 2011 caused the borrowing capacity under the facility to be limited to $440 million as of September 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.

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(Unaudited)

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 September 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

Our $600 million midstream syndicated revolving bank credit facility is used 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. We were in compliance with all covenants under the agreement at September 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 and one of the assets in 2011. As of September 30, 2011, we had 110 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 compression operating segment is responsible for marketing, gathering and compression of natural gas and oil primarily from Chesapeake-operated wells. We also have contract drilling, oilfield trucking, oilfield rental and other oilfield service operations which are responsible for providing services for both Chesapeake-operated wells and wells operated by third parties. Our contract drilling, oilfield trucking, oilfield rental and other oilfield service operations are included in Other Operations in the following table:

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(Unaudited)

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 $1.324 billion, $1.045 billion, $3.739 billion and $2.978 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.

	Intercompany Exploration and Production	Intercompany Marketing, Gathering and Compression	Intercompany Other Operations	Intercompany Intercompany Eliminations	Intercompany Consolidated Total
			($ in millions)		
Three Months Ended September 30, 2011:					
Revenues	$ 2,402	$ 2,746	$ 343	$ (1,514)	$ 3,977
Intersegment revenues		(1,324)	(190)	1,514	
Total revenues	$ 2,402	$ 1,422	$ 153	$	$ 3,977
Income before income taxes	$ 1,496	$ 79	$ 23	$ (87)	$ 1,511
Three Months Ended September 30, 2010:					
Revenues	$ 1,639	$ 1,928	$ 187	$ (1,173)	$ 2,581
Intersegment revenues		(1,045)	(128)	1,173	
Total revenues	$ 1,639	$ 883	$ 59	$	$ 2,581
Income (loss) before income taxes	$ 822	$ 96	$ (7)	$ (4)	$ 907
Nine Months Ended September 30, 2011:					
Revenues	$ 4,688	$ 7,583	$ 866	$ (4,229)	$ 8,908
Intersegment revenues		(3,739)	(490)	4,229	
Total revenues	$ 4,688	$ 3,844	$ 376	$	$ 8,908
Income before income taxes	$ 2,007	$ 239	$ 66	$ (231)	$ 2,081

Nine Months Ended September 30, 2010:										
Revenues	$	4,698	$	5,498	$	538	$	(3,343)	$	7,391
Intersegment revenues				(2,978)		(365)		3,343		
Total revenues	$	4,698	$	2,520	$	173	$		$	7,391
Income (loss) before income taxes	$	2,401	$	152	$	(32)	$	(1)	$	2,520
As of September 30 2011:										
Total assets	$	35,991	$	3,885	$	1,604	$	(1,358)	$	40,122
As of December 31, 2010:										
Total assets	$	33,560	$	3,458	$	854	$	(693)	$	37,179

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(Unaudited)

8. Acquisitions and Divestitures

Acquisition of Bronco Drilling

In June 2011, we acquired Bronco Drilling Company, Inc. (Nasdaq/GS:BRNC) for an aggregate purchase price of approximately $339 million, or $11.00 per share of Bronco common stock. 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	42
Intangible assets	10
Other	12
Total assets acquired	397
Current liabilities	33
Long-term liabilities	1
Deferred income taxes	24
Total liabilities assumed	58
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 $24 million. We recorded goodwill of $42 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. 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. None of the goodwill is deductible for tax purposes. The drilling rigs and equipment we acquired from Bronco are now owned by Nomac Drilling, L.L.C., our drilling subsidiary.

Fayetteville Shale Asset Sale

On March 31, 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP;ASX:BHP), for net proceeds of approximately $4.65 billion in cash. The 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 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 September 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 resource plays and received cash of $6.5 billion and commitments for future drilling and completion cost sharing of $7.7 billion. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. 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.

Primary Play	Joint Venture Partner[(a)]	Joint Venture Date	Interest Acquired	Cash Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining[(b)]
					($ in millions)	
Niobrara	CNOOC	February 2011	33.3%	$ 570	$ 697	$ 607
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	467
Barnett	TOT	January 2010	25.0%	800	1,450	471[(c)]
Marcellus	STO	November 2008	32.5%	1,250	2,125	564
Fayetteville	BP	September 2008	25.0%	1,100	800	
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508	
				$ 6,490	$ 7,660	$ 2,109

(a) Joint venture partners include CNOOC Limited (CNOOC), Total S.A. (TOT), Statoil (STO), BP America (BP) and Plains Exploration & Production Company (PXP).

(b) As of September 30, 2011.

(c) On October 24, 2011, Total accelerated the payment of its remaining joint venture carry in exchange for an approximate 9% reduction to the total amount of drilling carry obligation due to us. See Note 13 for this subsequent event.

During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $1.868 billion and $745 million, respectively, in drilling and completion carries paid by our joint venture partners, CNOOC, Total and Statoil.

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 $474 million and $395 million, respectively.

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(Unaudited)

Volumetric Production Payments

From time to time, we have monetized certain of our producing assets which are located in 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 September 30, 2011 and December 31, 2010, we had the following investments:

	Approximate % Owned	Accounting Method	Carrying Value September 30, 2011	Carrying Value December 30 2010
			($ in millions)	
Chesapeake Midstream Partners, L.P.	42%	Equity	$ 696	$ 695
FTS International, LLC	30%[(a)]	Equity	202	311
Chaparral Energy, Inc.	20%	Equity	130	133
Clean Energy Fuels Corp.		Cost	50	
Sundrop Fuels, Inc.	25%	Equity	35	
Gastar Exploration Ltd.	10%	Cost	20	29
Other		Cost/Equity	33	40
			$ 1,166	$ 1,208

(a) Formerly Frac Tech International, LLC. 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. As of September 30, 2011, common units owned by public security holders represented 17.7% of all outstanding limited partner interests, and Chesapeake and GIP held 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 $55 million for our share of CHKM s income, received cash distributions of $63 million from CHKM and recorded accretion adjustments of $9 million related to 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 $229 million as of September 30, 2011. This difference is being accreted over 20 years.

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(Unaudited)

FTS International, LLC. FTS International, LLC (FTS), 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 FTS s predecessor, Frac Tech Holdings, L.L.C., which resulted in a recapitalization that increased our equity ownership from 26% to 30%. We also entered into a master frac services agreement that obligates us to use certain services of FTS through 2014. Based on the valuation of the net assets performed by FTS in conjunction with the change in controlling ownership, the carrying value of our investment in FTS is less than our underlying equity in FTS s net assets by approximately $870 million as of September 30, 2011. We allocated this difference to the tangible and intangible assets of FTS and will accrete the portion attributable to the non-goodwill assets over their estimated lives of nine years.

In the Current Period, we recorded positive equity method adjustments of $104 million for our share of FTS s income, received cash distributions of $224 million from FTS and recorded accretion adjustments of $11 million.

Clean Energy Fuels Corp. 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 is being 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 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.

Sundrop Fuels, Inc. 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.

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. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $55 million as of September 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. In the Current Period, we recorded a $1 million charge related to our share of Chaparral s net loss and depreciation adjustments of $2 million related to the excess of our cost over our proportionate share of Chaparral s book equity.

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 $3.00 per share. Our investment in Gastar had a historical cost basis of $89 million as of September 30, 2011.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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. These values are reviewed internally for reasonableness using future interest rate curves and time to maturity. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of related qualifying interest rate swaps.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of September 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	$ 111	$	$	$ 111
Investments	20			20
Other long-term assets	61			61
Other long-term liabilities	(55)			(55)
Derivatives:				
Commodity assets		11	98	109
Commodity liabilities		(15)	(1,650)	(1,665)
Interest rate liabilities		(46)		(46)
Foreign currency liabilities		(31)		(31)
Total derivatives		(81)	(1,552)	(1,633)
Total	$ 137	$ (81)	$ (1,552)	$ (1,496)

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 (Continued)

(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.

	Derivatives			
	Commodity	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]	(50)			
Included in earnings or change in net assets (unrealized)[a]	306	21		
Included in other comprehensive income (loss)				
Total purchases, issuances, sales and settlements:				
Sales		(6)		
Settlements	146			
Transfers in and out of Level 3[b]		54	43	1,371
Ending Balance as of September 30, 2011	$ (1,552)	$	$	$
Beginning Balance as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses):				
Included in earnings (realized)[a]	305	(6)		
Included in earnings or change in net assets (unrealized)[a]	(669)	85	(44)	32
Included in other comprehensive income (loss)	(18)		(34)	
Total purchases, issuances, sales and settlements:				
Issuances				(700)[c]
Sales		(6)		
Settlements	(142)	20		1,250 [c]
Transfers in and out of Level 3				
Ending Balance as of September 30, 2010	$ (1,190)	$ (39)	$ (35)	$ (816)

(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) 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.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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.

	September 30, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 11,759	$ 12,527	$ 12,631	$ 13,272
Convertible preferred stock	$ 3,062	$ 3,340	$ 3,065	$ 3,019

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 6 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our midstream subsidiary, CMD, is not a guarantor and is subject to covenants in the midstream revolving bank credit facility referred to in Note 6 that restrict it from paying dividends or distributions or making loans to Chesapeake. Beginning in the 2011 fourth quarter, Chesapeake Oilfield Services, L.L.C. and its subsidiaries will no longer be guarantors under our outstanding senior notes and contingent convertible senior notes. See Note 13 for this subsequent event.

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 September 30, 2011 and December 31, 2010 and for the three and nine months ended September 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 SEPTEMBER 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 88	$ 23	$	$ 111
Other	1	3,194	182	(18)	3,359
Total Current Assets	1	3,282	205	(18)	3,470
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting, net		29,644	4		29,648
Other property and equipment, net		3,858	1,632		5,490
Total Property and Equipment, Net		33,502	1,636		35,138
Other assets	166	900	787	(339)	1,514
Investments in subsidiaries and intercompany advances	2,371	293		(2,664)	
TOTAL ASSETS	$ 2,538	$ 37,977	$ 2,628	$ (3,021)	$ 40,122
CURRENT LIABILITIES:					
Current liabilities	$ 216	$ 5,704	$ 294	$ (19)	$ 6,195
Intercompany payable to (receivable) from parent	(22,574)	21,331	1,205	38	

Total Current Liabilities	(22,358)	27,035	1,499	19	6,195
LONG-TERM LIABILITIES:					
Long-term debt, net	8,226	3,236	327		11,789
Deferred income tax liabilities	341	3,065	156	(38)	3,524
Other liabilities	31	2,270	353	(338)	2,316
Total Long-Term Liabilities	8,598	8,571	836	(376)	17,629
STOCKHOLDERS EQUITY:					
Total Stockholders Equity	16,298	2,371	293	(2,664)	16,298
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,538	$ 37,977	$ 2,628	$ (3,021)	$ 40,122

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 2	$ 100	$	$ 102
Other	7	3,065	123	(31)	3,164
Total Current Assets	7	3,067	223	(31)	3,266
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting, net		27,822	4		27,826
Other property and equipment, net		3,246	1,306		4,552
Total Property and Equipment, Net		31,068	1,310		32,378
Other assets	166	669	700		1,535
Investments in subsidiaries and intercompany advances	1,217	269		(1,486)	
TOTAL ASSETS	$ 1,390	$ 35,073	$ 2,233	$ (1,517)	$ 37,179
CURRENT LIABILITIES:					
Current liabilities	$ 302	$ 4,082	$ 137	$ (31)	$ 4,490
Intercompany payable to (receivable) from parent	(23,664)	21,955	1,596	113	
Total Current Liabilities	(23,362)	26,037	1,733	82	4,490
LONG-TERM LIABILITIES:					
Long-term debt, net	8,934	3,612	94		12,640
Deferred income tax liabilities	482	1,885	130	(113)	2,384
Other liabilities	72	2,322	7		2,401
Total Long-Term Liabilities	9,488	7,819	231	(113)	17,425
STOCKHOLDERS EQUITY:					
Total Stockholders Equity	15,264	1,217	269	(1,486)	15,264

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	1,390	$	35,073	$	2,233	$	(1,517)	$	37,179

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED SEPTEMBER 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 2,402	$	$	$ 2,402
Marketing, gathering and compression sales		1,393	55	(26)	1,422
Oilfield services revenue		129	24		153
Total Revenues		3,924	79	(26)	3,977
OPERATING COSTS:					
Production expenses		282			282
Production taxes		50			50
General and administrative expenses		143	8		151
Marketing, gathering and compression expenses		1,377	30	(15)	1,392
Oilfield services expense		94	24		118
Natural gas and oil depreciation, depletion and amortization		423			423
Depreciation and amortization of other assets		59	16		75
Losses on sales of other property and equipment		1	2		3
Total Operating Costs		2,429	80	(15)	2,494
INCOME (LOSS) FROM OPERATIONS		1,495	(1)	(11)	1,483
OTHER INCOME (EXPENSE):					
Interest expense	(138)	(17)	(7)	158	(4)
Earnings on investments		4	24		28
Other income	152	9	1	(158)	4
Equity in net earnings of subsidiary	914	4		(918)	
Total Other Income	928		18	(918)	28
INCOME BEFORE INCOME TAXES	928	1,495	17	(929)	1,511
INCOME TAX EXPENSE	6	581	6	(4)	589
NET INCOME	$ 922	$ 914	$ 11	$ (925)	$ 922

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED SEPTEMBER 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,639	$	$	$ 1,639
Marketing, gathering and compression sales		856	69	(42)	883
Oilfield services revenue		59			59
Total Revenues		2,554	69	(42)	2,581
OPERATING COSTS:					
Production expenses		231			231
Production taxes		34			34
General and administrative expenses	2	113	10		125
Marketing, gathering and compression expenses		838	37	(24)	851
Oilfield services expense		52			52
Natural gas and oil depreciation, depletion and amortization		378			378
Depreciation and amortization of other assets		43	13		56
Losses on sales of other property and equipment		2	15		17
Other impairments		1	19		20
Total Operating Costs	2	1,692	94	(24)	1,764
INCOME (LOSS) FROM OPERATIONS	(2)	862	(25)	(18)	817
OTHER INCOME (EXPENSE):					
Interest expense	(153)	(17)		167	(3)
Earnings on investments		43	108		151
Losses on purchases or exchanges of debt	(59)				(59)
Impairment of investments		(16)			(16)
Other income	167	4	13	(167)	17
Equity in net earnings of subsidiary	587	48		(635)	
Total Other Income	542	62	121	(635)	90
INCOME BEFORE INCOME TAXES	540	924	96	(653)	907
INCOME TAX EXPENSE (BENEFIT)	(18)	337	37	(7)	349

NET INCOME	$	558	$	587	$	59	$	(646)	$	558

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

NINE MONTHS ENDED SEPTEMBER 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 4,688	$	$	$ 4,688
Marketing, gathering and compression sales		3,766	153	(75)	3,844
Oilfield services revenue		351	25		376
Total Revenues		8,805	178	(75)	8,908
OPERATING COSTS:					
Production expenses		782			782
Production taxes		140			140
General and administrative expenses		387	23		410
Marketing, gathering and compression expenses		3,698	96	(50)	3,744
Oilfield services expense		262	25		287
Natural gas and oil depreciation, depletion and amortization		1,147			1,147
Depreciation and amortization of other assets		166	40		206
(Gains) losses on sales of other property and equipment		6	(3)		3
Other impairments			4		4
Total Operating Costs		6,588	185	(50)	6,723
INCOME (LOSS) FROM OPERATIONS		2,217	(7)	(25)	2,185
OTHER INCOME (EXPENSE):					
Interest expense	(488)	(42)	(9)	502	(37)
Earnings on investments		36	64		100
Losses on purchases or exchanges of debt	(176)				(176)
Other income	494	14	3	(502)	9
Equity in net earnings of subsidiary	1,373	16		(1,389)	
Total Other Income (Expense)	1,203	24	58	(1,389)	(104)
INCOME BEFORE INCOME TAXES	1,203	2,241	51	(1,414)	2,081
INCOME TAX EXPENSE (BENEFIT)	(66)	868	20	(10)	812
NET INCOME	$ 1,269	$ 1,373	$ 31	$ (1,404)	$ 1,269

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

NINE MONTHS ENDED SEPTEMBER 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 4,698	$	$	$ 4,698
Marketing, gathering and compression sales		2,437	179	(96)	2,520
Oilfield services revenue		173			173
Total Revenues		7,308	179	(96)	7,391
OPERATING COSTS:					
Production expenses		652			652
Production taxes		119			119
General and administrative expenses	2	315	23		340
Marketing, gathering and compression expenses		2,383	90	(44)	2,429
Oilfield services expense		154			154
Natural gas and oil depreciation, depletion and amortization		1,025			1,025
Depreciation and amortization of other assets		124	35		159
Losses on sales of other property and equipment		2	15		17
Other impairments		1	19		20
Total Operating Costs	2	4,775	182	(44)	4,915
INCOME (LOSS) FROM OPERATIONS	(2)	2,533	(3)	(52)	2,476
OTHER INCOME (EXPENSE):					
Interest expense	(451)	(109)	(1)	549	(12)
Earnings on investments		39	151		190
Losses on purchases or exchanges of debt	(130)				(130)
Impairment of investments		(16)			(16)
Other income	549	9	3	(549)	12
Equity in net earnings of subsidiary	1,571	60		(1,631)	
Total Other Income (Expense)	1,539	(17)	153	(1,631)	44
INCOME BEFORE INCOME TAXES	1,537	2,516	150	(1,683)	2,520
INCOME TAX EXPENSE (BENEFIT)	(13)	945	58	(20)	970

NET INCOME	$ 1,550	$ 1,571	$ 92	$ (1,663)	$ 1,550

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

NINE MONTHS ENDED SEPTEMBER 30, 2011

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 3,783	$ 166	$ (225)	$ 3,724
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(9,118)			(9,118)
Proceeds from divestitures of proved and unproved properties		6,357			6,357
Additions to other property and equipment		(632)	(784)		(1,416)
Other investing activities		(30)	93	399	462
Cash used in investing activities		(3,423)	(691)	399	(3,715)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		10,791	1,123		11,914
Payments on credit facilities borrowings		(11,167)	(890)		(12,057)
Proceeds from issuance of senior notes, net of offering costs	977				977
Cash paid to purchase debt	(2,015)				(2,015)
Other financing activities	(388)	1,558	185	(174)	1,181
Intercompany advances, net	1,426	(1,456)	30		
Cash provided by (used in) financing activities		(274)	448	(174)	
Net increase (decrease) in cash and cash equivalents		86	(77)		9
Cash and cash equivalents, beginning of period		2	100		102
Cash and cash equivalents, end of period	$	$ 88	$ 23	$	$ 111

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

NINE MONTHS ENDED SEPTEMBER 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 3,793	$ 178	$	$ 3,971
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(7,935)			(7,935)
Proceeds from divestitures of proved and unproved properties		3,107			3,107
Additions to other property and equipment		(412)	(556)		(968)
Other investing activities			131		131
Cash used in investing activities		(5,240)	(425)		(5,665)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		10,076	382		10,458
Payments on credit facilities borrowings		(9,736)	(127)		(9,863)
Proceeds from issuance of preferred stock, net of offering costs	2,562				2,562
Proceeds from issuance of senior notes, net of offering costs	1,967				1,967
Cash paid to purchase debt	(3,434)				(3,434)
Other financing activities	(243)	543	6		306
Intercompany advances, net	(852)	858	(6)		
Cash provided by financing activities		1,741	255		1,996
Net increase in cash and cash equivalents		294	8		302
Cash and cash equivalents, beginning of period		293	14		307
Cash and cash equivalents, end of period	$	$ 587	$ 22	$	$ 609

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Recently Issued and Proposed Accounting Standards

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

In September 2011, the FASB issued guidance related to the annual goodwill impairment test. The guidance provides entities with the option of performing a qualitative assessment to determine whether the two-step goodwill impairment test is necessary. The revised standard is effective for goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We do not expect this guidance to have a material effect on our financial condition or results of operations as it is a change in application of the goodwill impairment test only.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements and requires certain other disclosures. We are evaluating the impact of this guidance, which will be adopted effective January 1, 2012.

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 under 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

In conjunction with an agreement for us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, our joint venture partner, Total, accelerated the payment of its remaining joint venture drilling carry, in exchange for an approximate 9% reduction in the total amount of drilling carry obligations due to us. As a result, on October 24, 2011, we received $471 million in cash from Total which included $46 million of carry obligation billed and $425 million for all remaining carry obligations.

On October 28, 2011, our wholly owned subsidiary, Chesapeake Oilfield Operating, L.L.C. (COO), issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used a portion of the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, Chesapeake Oilfield Services, L.L.C., to enable it to reduce indebtedness under an intercompany note with Chesapeake. On November 3, 2011, COO established a five-year syndicated revolving bank credit facility with $500 million in total commitments (limited to $60 million as of November 3, 2011 by certain restrictive provisions). Borrowings under the credit facility are secured by liens on all of the equity interests of COO s current and future guarantor subsidiaries and all of their assets, including real and personal property.

COO is a diversified oilfield services company that we formed to own and operate our oilfield service assets. COO provides a wide range of well site services, primarily to Chesapeake and its working interest partners, including contract drilling, pressure pumping, tool rental, transportation and manufacturing of natural gas compressor packages and related production equipment. In connection with the reorganization of our oilfield services subsidiaries and operations in October 2011, those subsidiaries were all released from the guarantees and other credit support obligations that existed for the benefit of Chesapeake and its other subsidiaries, including Chesapeake s senior notes and contingent convertible senior notes, its corporate revolving bank credit facility and its multi-counterparty hedging facility. In addition, COO and its subsidiaries entered into agreements with Chesapeake pursuant to which they sublease rigs, provide certain oilfield services and obtain certain administrative services. The total assets of Chesapeake s oilfield services operations were approximately $1.364 billion as of September 30, 2011, and for the nine months ended September 30, 2011, those operations generated approximately $376 million of revenue and a net loss of $10 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

On November 2, 2011, we completed the sale of $500 million of perpetual preferred shares of a newly formed entity, CHK Utica, L.L.C. (CHK Utica). CHK Utica is an unrestricted subsidiary of Chesapeake that owns approximately 700,000 net leasehold acres within an area of mutual interest in the Utica Shale play in 13 counties, primarily in eastern Ohio. We have retained all the common interests in CHK Utica. The CHK Utica preferred shares are entitled to receive an initial annual distribution of 7%, payable quarterly. Chesapeake retains an option exercisable prior to October 31, 2018, to repurchase the preferred shares for cash in whole or in part at any time at a valuation expected to equal the greater of a 10% internal rate of return or a return on investment of 1.4x and may repurchase the shares thereafter at a higher valuation. Investors in CHK Utica preferred shares will also receive an overriding royalty interest in the wellbores of the first 1,500 net wells drilled in the area of mutual interest. As part of the transaction, we have committed to drill a minimum of 50 net wells per year through 2016 in the CHK Utica area of mutual interest, up to a minimum cumulative total of 250 net wells, for the benefit of CHK Utica.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Net Production:				
Natural gas (bcf)	254.2	252.8	731.9	689.6
Oil (mmbbl)[(a)]	8.7	4.5	21.9	12.8
Natural gas equivalent (bcfe)[(b)]	306.2	280.0	863.3	766.6
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 861	$ 828	$ 2,412	$ 2,504
Natural gas derivatives realized gains (losses)	364	487	1,322	1,418
Natural gas derivatives unrealized gains (losses)	(28)	315	(693)	534
Total natural gas sales	1,197	1,630	3,041	4,456
Oil sales[(a)]	566	246	1,480	739
Oil derivatives realized gains (losses)	(20)	25	(82)	66
Oil derivatives unrealized gains (losses)	659	(262)	249	(563)
Total oil sales	1,205	9	1,647	242
Total natural gas and oil sales	$ 2,402	$ 1,639	$ 4,688	$ 4,698
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 3.39	$ 3.28	$ 3.30	$ 3.63
Oil ($ per bbl)[(a)]	$ 65.29	$ 54.25	$ 67.53	$ 57.57
Natural gas equivalent ($ per mcfe)	$ 4.66	$ 3.84	$ 4.51	$ 4.23
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 4.82	$ 5.20	$ 5.10	$ 5.69
Oil ($ per bbl)[(a)]	$ 63.03	$ 59.81	$ 63.80	$ 62.75
Natural gas equivalent ($ per mcfe)	$ 5.78	$ 5.67	$ 5.94	$ 6.17
Other Operating Income[(c)] ($ in millions):				
Marketing, gathering and compression net margin	$ 30	$ 32	$ 100	$ 91
Oilfield services net margin	$ 35	$ 7	$ 89	$ 19
Other Operating Income[(c)] ($ per mcfe):				
Marketing, gathering and compression net margin	$ 0.10	$ 0.12	$ 0.12	$ 0.12
Oilfield services net margin	$ 0.11	$ 0.03	$ 0.10	$ 0.03
Expenses ($ per mcfe):				
Production expenses	$ 0.92	$ 0.83	$ 0.91	$ 0.85
Production taxes	$ 0.16	$ 0.12	$ 0.16	$ 0.16
General and administrative expenses	$ 0.49	$ 0.45	$ 0.47	$ 0.44
Natural gas and oil depreciation, depletion and amortization	$ 1.38	$ 1.35	$ 1.33	$ 1.34
Depreciation and amortization of other assets	$ 0.24	$ 0.20	$ 0.24	$ 0.21
Interest expense[(d)]	$ 0.01	$	$ 0.03	$ 0.11

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Interest Expense (Income) ($ in millions):				
Interest expense	$ 4	$ 3	$ 18	$ 93
Interest rate derivatives realized (gains) losses		(2)	6	(6)
Interest rate derivatives unrealized (gains) losses		2	13	(75)
Total interest expense	$ 4	$ 3	$ 37	$ 12

(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, a top 15 producer of oil and natural gas liquids and the most active driller of new wells in the U.S. We own interests in approximately 45,000 producing natural gas and oil wells that are currently producing approximately 3.5 bcfe per day, net to our interest. 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 Mississippi Lime 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 and oilfield services assets as discussed below under *Our Strategy*.

Chesapeake began 2011 with estimated proved reserves of 17.096 tcfe and ended the Current Period with 17.677 tcfe, an increase of 581 bcfe, or 3%. 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. The Current Period s proved reserve movement included 863 bcfe of production, 3.717 tcfe of extensions, 471 bcfe of positive performance revisions and 13 bcfe of downward revisions resulting from lower natural gas prices using the average first-day-of-the-month price for the twelve months ended September 30, 2011, compared to the twelve months ended December 31, 2010. During the Current Period, we acquired 29 bcfe of estimated proved reserves and divested 2.760 tcfe of estimated proved reserves.

During the Current Period, we invested $4.276 billion in operated wells (using an average of 165 operated rigs) and $1.136 billion in non-operated wells (using an average of 103 non-operated rigs) for total drilling and completing costs on proved and unproved properties of $5.412 billion, net of drilling and completion carries of $1.868 billion.

Our total Current Quarter production of 306.2 bcfe consisted of 254.2 bcf of natural gas (83% on a natural gas equivalent basis) and 8.7 mmbbls of oil and natural gas liquids (17% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 3.329 bcfe, an increase of 286 mmcfe, or 9%, over the 3.043 bcfe produced per day in the Prior Quarter.

Our total Current Period production of 863.3 bcfe consisted of 731.9 bcf of natural gas (85% on a natural gas equivalent basis) and 21.9 mmbbls of oil and natural gas liquids (15% on a natural gas equivalent basis). Daily production for the Current Period averaged 3.162 bcfe, an increase of 354 mmcfe, or 13%, over the 2.808 bcfe produced per day in the Prior Period.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (15.0 million net acres) and 3-D seismic (30.1 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 171 operated drilling rigs to further develop our inventory of approximately 38,700 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, Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise during the past three years to identify, secure and commercialize new unconventional liquids-rich plays. This planned transition will result in a more balanced and likely more profitable portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple liquids-rich plays on approximately 6.2 million net acres. Our production of oil and natural gas liquids averaged 80,253 bbls per day during the Current Period, a 71% 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 an average of approximately 150,000 bbls per day in 2012, 200,000 bbls per day in 2013 and 250,000 bbls per day by 2015.

Reduce Debt and Grow Production. 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 had increased our production forecast, and we 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 reduced leasehold spending during this two-year 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+.

Vertically Integrate Oilfield Services. 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. This high level of 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 focus our oilfield services asset investments where we believe services are scarce or have relatively high margins. We utilize our oilfield services operations as a financial and operational hedge against oilfield service inflation. In October 2011, we formally segregated our oilfield services subsidiaries under Chesapeake Oilfield Services, L.L.C. and its wholly owned subsidiary Chesapeake Oilfield Operating, L.L.C.

To date, we have invested in drilling rigs, compression equipment, rental tools, water management equipment, trucking, midstream services and most recently, pressure pumping 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, reduces turnover among operating teams, creates an alignment of interests, creates operational synergies, provides greater access to equipment, and increases safety and better coordinated logistics. In addition, our control of a large portion of the oilfield services equipment we utilize provides unique advantages in accelerating the timing of our leasehold development and therefore accelerating the value we are able to realize from our large inventory of undeveloped properties.

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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 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

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.

As of September 30, 2011, including the joint venture described above, 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 resource plays and received cash of $6.5 billion and commitments for future drilling and completion cost sharing of $7.7 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. These transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. 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.

Primary Play	Joint Venture Partner[(a)]	Joint Venture Date	Interest Acquired	Cash Proceeds Received at Closing	Total Drilling Carries	Drilling Carries Remaining[(b)]
					($ in millions)	
Niobrara	CNOOC	February 2011	33.3%	$ 570	$ 697	$ 607
Eagle Ford & Pearsall	CNOOC	November 2010	33.3%	1,120	1,080	467
Barnett	TOT	January 2010	25.0%	800	1,450	471[(c)]
Marcellus	STO	November 2008	32.5%	1,250	2,125	564
Fayetteville	BP	September 2008	25.0%	1,100	800	
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508	
				$ 6,490	$ 7,660	$ 2,109

(a) Joint venture partners include CNOOC Limited (CNOOC), Total S.A. (TOT), Statoil (STO), BP America (BP) and Plains Exploration & Production Company (PXP).

(b) As of September 30, 2011.

(c) On October 24, 2011, Total accelerated the payment of its remaining joint venture carries in exchange for an approximate 9% reduction to the total amount of drilling carry obligation due to us.

The drilling and completion carries in our joint venture agreements create a significant cost advantage that allows us to reduce our future finding costs. During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $1.868 billion and $745 million, respectively, of

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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.

In conjunction with an agreement for us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, Total accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligations due to us. As a result, on October 24, 2011, we received $471 million in cash from Total which included $46 million of carry obligation billed and $425 million for all remaining carry obligations.

We have recently entered into a letter of intent for an industry joint venture to develop a portion of our Utica Shale acreage in eastern Ohio. This transaction is described below under *Future Steps to Implement our Strategy Utica Shale Joint Venture.*

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 $474 million that had an estimated cost to us of approximately $291 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

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.

Volumetric Production Payments (VPPs). In May 2011, we monetized certain of our producing assets in the Mid-Continent through a ten-year VPP for proceeds of approximately $853 million. The transaction included approximately 177 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 were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Other VPPs we completed in 2007 2010 are detailed in Note 8 of the consolidated financial statements included in this report.

Frac Tech Ownership Change. Through our investment in FTS International, LLC, the holding company of Frac Tech Services, LLC, we have a 30% equity interest in what we believe is the third largest onshore pressure pumping and well stimulation company in the U.S. based on the total horsepower of its fleets. On May 6, 2011, there was a change in controlling ownership of FTS s predecessor, Frac Tech Holdings, L.L.C. During the Current Period, we also received a cash distribution of approximately $224 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 Frac Tech through 2014.

Bronco Drilling Acquisition. As an extension of our vertical integration strategy, in June 2011 we acquired Bronco Drilling Company, Inc. (Nasdaq/GS:BRNC) for an aggregate purchase price of approximately $339 million, or $11.00 per share of Bronco common stock. The acquisition included 22 high-quality drilling rigs primarily operating in the Williston and Anadarko basins which were transferred to our drilling subsidiary, Nomac Drilling, L.L.C.

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 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. If certain requirements have been met 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.

Oilfield Services Capitalization. On October 28, 2011, our wholly owned subsidiary, Chesapeake Oilfield Operating, L.L.C. (COO), issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used a portion of the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, Chesapeake Oilfield Services, L.L.C., to enable it to reduce indebtedness under an intercompany note with Chesapeake. On November 3, 2011, COO established a five-year syndicated revolving bank credit facility with $500 million in total commitments (limited to $60 million as of November 3, 2011 by certain restrictive provisions). Borrowings under the credit facility are secured by liens on all of the equity interests of COO and COO s current and future guarantor subsidiaries and all of their assets, including real and personal property.

COO is a diversified oilfield services company that we formed to own and operate our oilfield service assets. COO provides a wide range of well site services, primarily to Chesapeake and its working interest partners, including contract drilling, pressure pumping, tool rental, transportation, and manufacturing of natural gas compressor packages and related production equipment. In connection with the reorganization of our oilfield service subsidiaries and operations, in October 2011, those subsidiaries were all released from the guarantees and other credit support obligations that existed for the benefit of Chesapeake and its other subsidiaries, including Chesapeake s senior notes and contingent convertible senior notes, its corporate revolving bank credit facility and its multi-counterparty hedging facility. In addition, COO and its subsidiaries entered into agreements with Chesapeake pursuant to which they sublease rigs, provide certain oilfield services and obtain certain administrative services. The total assets of Chesapeake s oilfield services operations were approximately $1.364 billion as of September 30, 2011, and for the nine months ended September 30, 2011, those operations generated approximately $376 million of revenue and a net loss of approximately $10 million.

Utica Financial Transaction. On November 2, 2011, we completed the sale of $500 million of perpetual preferred shares of a newly formed entity, CHK Utica, L.L.C. (CHK Utica). CHK Utica is an unrestricted subsidiary of Chesapeake that owns approximately 700,000 net leasehold acres within an area of mutual interest in the Utica Shale play in 13 counties, primarily in eastern Ohio. We have retained all the common interests in CHK Utica. The CHK Utica preferred shares are entitled to receive an initial annual distribution of 7%, payable quarterly. Chesapeake retains an option exercisable prior to October 31, 2018 to repurchase the preferred shares for cash in whole or in part at any time at a valuation expected to equal the greater of a 10% internal rate of return or a return on investment of 1.4x and may repurchase the shares thereafter at a higher valuation. Investors in CHK Utica preferred shares will also receive an overriding royalty interest in the wellbores of the first 1,500 net wells drilled in the area of mutual interest. As part of the transaction, we have committed to drill a minimum of 50 net wells per year through 2016 in the CHK Utica area of mutual interest, up to a minimum cumulative total of 250 net wells, for the benefit of CHK Utica. We anticipate selling up to an additional $750 million of CHK Utica preferred shares by November 30, 2011.

Future Steps to Implement Our Strategy

Royalty Trust Offering. On November 2, 2011, Chesapeake Granite Wash Trust (the Trust), a newly formed Delaware statutory trust, commenced an initial public offering of 23,375,000 common units representing an approximate 50% beneficial interest in the Trust. The Trust has also granted the underwriters the option to purchase up to an additional 3,506,250 common units. The common units being offered to the public have been approved for listing on the New York Stock Exchange under the symbol CHKR , subject to official notice of issuance. 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 will entitle the Trust to a percentage of the proceeds received by Chesapeake from the production of hydrocarbons from 69 currently producing wells and 118 development wells to be drilled by Chesapeake by June 30, 2016 on approximately 45,400 gross acres (28,700 net acres) in the Colony Granite Wash play in Washita County in western Oklahoma. 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 and the registration statement relating to the offering has not been declared effective by the Securities and Exchange and Commission (SEC). If we complete this transaction, we intend to use the net proceeds from the offering to repay borrowings under our corporate revolving bank credit facility.

We have determined that our equity interest in the Trust will constitute a variable interest, that the Trust will be a variable interest entity and that we will be the primary beneficiary of the Trust. As a result, we expect to consolidate the activities of the Trust into our results beginning in the fourth quarter of 2011. In consolidation, the common units of the Trust owned by third parties will be reflected as a noncontrolling interest.

Utica Shale Joint Venture. On November 3, 2011, we announced that we had entered into a letter of intent with an undisclosed international major energy company for an industry joint venture in the wet natural gas area of the Utica Shale play. Under the terms of the letter of intent, the joint venture partner will acquire an undivided 25% interest in approximately 650,000 net acres of leasehold, of which Chesapeake owns approximately 570,000 net acres, covering all or a portion of 10 counties in eastern Ohio. The consideration for the transaction will be $15,000 per net acre, or approximately $2.14 billion to Chesapeake. Approximately $640 million of the consideration will be paid in cash at closing and approximately $1.5 billion will be paid in the form of a drilling and completion cost carry, which we anticipate fully receiving by year-end 2014. The joint venture partner will have the right to acquire a 25% share of all additional acreage we acquire in the joint venture area of mutual interest. The letter of intent provides for the execution of definitive transaction documents and closing by mid-December 2011. Completion of the transaction is subject to the negotiation and execution and delivery of definitive agreements, and we cannot assure that it will occur on the terms described or at all. Changes in market conditions or other factors beyond our control could adversely affect our ability to consummate the transaction.

Other Planned Asset Monetizations. By year-end 2012, we expect to enter into additional asset monetizations, potentially including the sale of additional shares of CHK Utica preferred shares, joint ventures, production monetizations (such as VPPs and/or royalty trusts), midstream asset sales, the further monetization of our oilfield services subsidiary, the sale of some or all of our equity interests in Chaparral Energy, Inc. and FTS International, L.L.C., 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 2011 and $6.2 $6.8 billion in 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.

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 $3.724 billion in the Current Period compared to $3.971 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. As natural gas and oil prices dip and reach supportable low prices, however, we may take the opportunity to close out open swap positions in order to lock in substantial mark-to-market gains. For example, in the Current Period, we have elected to close all our natural gas swap positions thereby locking in approximately $1.3 billion of gains and positioning us to be able to react to market increases in the future by potentially adding new positions. Our natural gas and oil derivatives as of September 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 derivative 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 $1.085 billion and $436 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 proved and unproved property divestiture proceeds of $6.357 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, $474 million of joint venture leasehold sales and $150 million from other transactions. Prior Period proved and unproved property divestiture proceeds of $3.107 billion included $800 million in cash at the closing of our Barnett Shale joint venture, $1.665 billion from our sixth, seventh and eighth VPP transactions, $395 million of joint venture leasehold sales and $247 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 (currently limited to $440 million), our $500 million oilfield services revolving bank credit facility (currently limited to $60 million) 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 $11.914 billion and repaid $12.057 billion in the Current Period, and we borrowed $10.458 billion and repaid $9.863 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 and oilfield services facilities are secured by substantially all of their respective wholly owned assets and are not subject to periodic borrowing base redeterminations. Our revolving bank credit facilities are described below under *Bank Credit Facilities*.

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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.

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.

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 $151 million and $142 million in the Current Period and the Prior Period, respectively. The Board of Directors increased the quarterly dividend of common stock from $0.075 to $0.0875 per share beginning with the dividend paid in July 2011. Dividends paid on our preferred stock increased to $128 million in the Current Period from $49 million in the Prior Period as a result of the issuance of two series of 5.75% Cumulative Convertible Preferred Stock.

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Credit Risk

Derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. 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 September 30, 2011, our commodity and interest rate derivative instruments were spread among 12 counterparties. Additionally, our multi-counterparty secured hedging facility included 11 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 natural gas, oil and natural gas liquids derivatives.

Our accounts receivable are primarily from purchasers of natural gas and oil ($1.110 billion at September 30, 2011) and exploration and production companies which own interests in properties we operate ($1.383 billion at September 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 $3.715 billion during the Current Period, compared to $5.665 billion during the Prior Period. The majority of the $1.950 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 $3.249 billion and $3.575 billion, respectively. Drilling and completion costs on proved and unproved properties increased $1.601 billion to $5.177 billion in the Current Period compared to $3.576 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:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Acquisitions of proved properties	$ (46)	$ (139)
Acquisitions of unproved properties	(3,249)	(3,575)
Drilling and completion costs on proved and unproved properties	(5,177)	(3,576)
Geological and geophysical costs[(a)]	(168)	(142)
Interest capitalized on unproved properties	(478)	(503)
Proceeds from divestitures of proved and unproved properties	6,357	3,107
Other		(95)
Total natural gas and oil investing activities	(2,761)	(4,923)
Other Investing Activities:		
Additions to other property and equipment	(1,416)	(968)
Proceeds from (additions to) investments	126	(113)
Proceeds from sales of other assets	682	328
Acquisition of drilling company	(339)	
Other	(7)	11
Total other investing activities	(954)	(742)
Total cash used in investing activities	$ (3,715)	$ (5,665)

(a) Including related capitalized interest.

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Bank Credit Facilities

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

	Corporate Credit Facility[(a)]	Midstream Credit Facility[(b)] ($ in millions)	Oilfield Services Credit Facility[(c)]
Facility structure	Senior secured revolving	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	June 2016	November 2016
Borrowing capacity	$ 4,000	$ 600[(d)]	$ 500[(e)]
Amount outstanding as of September 30, 2011	$ 3,236	$ 327	$
Letters of credit outstanding as of September 30, 2011	$ 60	$	$

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

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

(c) Borrower is Chesapeake Oilfield Operating, L.L.C. This facility was established on November 3, 2011.

(d) The decrease in operating income following the sale of our Haynesville Springridge gathering system in December 2010 and the sale of our Fayetteville gathering system in March 2011 caused the borrowing capacity under the facility to be limited to $440 million as of September 30, 2011.

(e) As a result of reduced operating cash flow at the beginning of the twelve-month period ended September 30, 2011, the initial facility capacity was limited to $60 million.

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, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective 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.

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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 September 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

Our $600 million midstream syndicated revolving bank credit facility is used 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 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 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. We were in compliance with all covenants under the agreement at September 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.

Oilfield Services Credit Facility

On November 3, 2011, we closed on a new syndicated revolving bank credit facility for our oilfield services operations, which have recently been segregated under the wholly owned subsidiary Chesapeake Oilfield Services, L.L.C. and its wholly owned subsidiary Chesapeake Oilfield Operating, L.L.C. (COO). The facility matures in November 2016, has initial availability of $500 million and may be expanded to $900 million at COO s option, subject to additional bank participation. The facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the credit facility are secured by all of the assets of COO and its wholly owned subsidiaries, and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, and 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 LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the credit 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 oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO 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 lease adjusted indebtedness to EBITDAR, a senior secured leverage ratio based on a ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of lease adjusted interest expense to EBITDAR, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at the closing of the facility. If COO 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 oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO 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 18 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 $17.5 billion under the terms of the facility. As of September 30, 2011, we had hedged under the facility 2.0 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.

Senior Note Obligations

As of September 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)]		463
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)]		(509)
Interest rate derivatives[(d)]		30
	$	8,226

(a) The principal amount shown is based on the exchange rate of $1.3449 to 1.00 as of September 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 third 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 fourth 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 $460 million at September 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.

On October 28, 2011, our wholly owned subsidiary, COO, issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used a portion of the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, Chesapeake Oilfield Services, L.L.C., to enable it to reduce indebtedness under an intercompany note with Chesapeake.

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, excluding CMD and its subsidiaries and, beginning in the 2011 fourth quarter, Chesapeake Oilfield Services, L.L.C. and its 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 September 30, 2011. These include commitments related to drilling rig and compressor leases, gathering, processing and transportation agreements, drilling contracts, natural gas and oil purchase obligations, net acreage maintenance requirements for joint ventures, pressure pumping service obligations and investment agreements. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in this report.

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

General. For the Current Quarter, Chesapeake had net income of $922 million, or $1.23 per diluted common share, on total revenues of $3.977 billion. This compares to net income of $558 million, or $0.75 per diluted common share, on total revenues of $2.581 billion during the Prior Quarter.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $2.402 billion compared to $1.639 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 306.2 bcfe at a weighted average price of $5.78 per mcfe, compared to 280.0 bcfe produced and sold in the Prior Quarter at a weighted average price of $5.67 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of $631 million and $53 million in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $35 million and increased production resulted in a $149 million increase, for a total increase in revenues of $184 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 $4.82, compared to $5.20 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). In the Current Quarter and the Prior Quarter, realized prices of natural gas include 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 September 30, 2011. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $63.03 and $59.81 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 $344 million, or $1.12 per mcfe, in the Current Quarter and a net increase of $512 million, or $1.83 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 $25 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 $9 million and $8 million, respectively, without considering the effect of hedging activities.

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

	Three Months Ended September 30, 2011						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	110.5	3.47			110.5	36	3.47
Mid-Continent	56.9	3.94	5.4	63.37	89.3	29	6.34
Barnett Shale[c]	35.6	2.11	0.3	39.71	37.3	12	2.32
Marcellus Shale	30.6	3.71	0.4	57.94	33.0	11	4.18
Fayetteville Shale							
Permian and Delaware Basins	8.9	3.43	1.6	75.78	18.4	6	8.17
Eagle Ford Shale	1.6	1.37	0.8	66.72	6.4	2	8.66
Rockies/Williston Basin	0.1	4.89	0.1	83.52	0.7		12.11
Other	10.0	3.15	0.1	78.38	10.6	4	3.70
Total[d]	254.2	3.39	8.7	65.29	306.2	100	4.66

	Three Months Ended September 30, 2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	69.4	3.65			69.4	25	3.65
Mid-Continent	58.9	3.42	3.5	52.43	79.9	29	4.81
Barnett Shale[c]	50.9	2.33	0.2	24.06	52.1	19	2.37
Marcellus Shale	14.9	4.04			14.9	5	4.04
Fayetteville Shale	36.0	3.07			36.0	13	3.07
Permian and Delaware Basins	10.5	3.85	0.6	70.43	14.2	5	5.96
Eagle Ford Shale	0.3	4.55	0.1	74.23	0.9		9.48
Rockies/Williston Basin	0.1	2.47			0.1		2.47
Other	11.8	3.58	0.1	61.64	12.5	4	3.86
Total	252.8	3.28	4.5	54.25	280.0	100	3.84

(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. Additionally, the rapid development of the Barnett Shale required the construction of new pipelines to provide an adequate market for these new gas reserves. In order to support the timely construction of these new pipelines, we entered into firm transportation contracts that obligate the company to pay demand fees if we do not deliver specified volumes of natural gas into certain gathering systems and intrastate pipelines. The demand fees associated with unused capacity and the other gathering and transportation fees described above have resulted in lower natural gas price realizations in the Barnett Shale.

(d) The Current Quarter production reflects the sale of all of our Fayetteville Shale assets, which closed in March 2011 and various other asset sales, including VPP #8 and VPP #9, which closed in September 2010 and May 2011, respectively.

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Our average daily production of 3.329 bcfe for the Current Quarter consisted of 2.763 bcf of natural gas and 94,228 bbls of oil and natural gas liquids (collectively liquids). Our Current Quarter production of 306.2 bcfe consisted of 254.2 bcf of natural gas (83% on a natural gas equivalent basis) and 8.7 mmbbls of liquids (17% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 1% and our year-over-year growth rate of liquids production was 91%. Our percentage of revenue from liquids in the Current Quarter was 40% of unhedged natural gas and oil revenue compared to 23% in the Prior Quarter.

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression sales and expenses consist of third-party revenue and operating expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $1.422 billion in marketing, gathering and compression sales in the Current Quarter with corresponding expenses of $1.392 billion, for a net margin before depreciation of $30 million. This compares to sales of $883 million, expenses of $851 million and a net margin before depreciation of $32 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in marketing, gathering and compression sales and expenses primarily due to an increase in third-party marketing, gathering and compression volumes.

Oilfield Services Revenue and Expenses. Oilfield services consists of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $153 million in oilfield services revenue in the Current Quarter with corresponding expenses of $118 million, for a net margin before depreciation of $35 million. This compares to revenue of $59 million, expenses of $52 million and a net margin before depreciation of $7 million in the Prior Quarter. Oilfield services margins have increased as service rates increased throughout 2010 and 2011 in addition to an increase in services provided to third parties.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $282 million in the Current Quarter and $231 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.92 per mcfe in the Current Quarter compared to $0.83 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 $50 million in the Current Quarter compared to $34 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.16 per mcfe in the Current Quarter compared to $0.12 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 $16 million increase in production taxes in the Current Quarter is primarily due to an increase in the average sales price of natural gas and oil of $0.82 per mcfe (excluding gains or losses on derivatives) and an increase in production of 26 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 $151 million in the Current Quarter and $125 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 $0.49 and $0.45 per mcfe for the Current Quarter and Prior Quarter, respectively. Included in general and administrative expenses is stock-based compensation of $24 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 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, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, drilling and completion 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 $116 million and $98 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, drilling and completion efforts and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas and oil properties was $423 million and $378 million during the Current Quarter and the Prior Quarter, respectively. The $45 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 $1.38 and $1.35 in the Current Quarter and in the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $75 million in the Current Quarter and $56 million in the Prior Quarter. Depreciation and amortization of other assets was $0.24 and $0.20 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 drilling and completion costs.

Losses on Sales of Other Property and Equipment. Losses on sales of other property, plant and equipment were $3 million in the Current Quarter and $17 million in the Prior Quarter. These losses were related to various sales of other property, plant and equipment, including the sale of pipe, gas gathering systems and other miscellaneous assets.

Other Impairments. In the Prior Quarter, we recorded a $20 impairment charge related to obsolete pipe inventory.

Interest Expense. Interest expense was $4 million in the Current Quarter compared to $3 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2011	2010
	($ in millions)	
Interest expense on senior notes	$ 152	$ 167
Interest expense on credit facilities	18	18
Realized (gain) loss on interest rate derivatives		(2)
Unrealized (gain) loss on interest rate derivatives		2
Amortization of loan discount and other	8	3
Capitalized interest	(174)	(185)
Total interest expense	$ 4	$ 3
Average long-term borrowings	$ 8,700	$ 9,632

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.01 per mcfe in the Current Quarter compared to a nominal amount per mcfe in the Prior Quarter.

Earnings on Investments. Earnings on investments were $28 million and $151 million in the Current Quarter and the Prior Quarter, respectively. The Prior Quarter included a $121 million gain related to the initial public offering by Chesapeake Midstream Partners, L.P. (CHKM), our midstream master limited partnership affiliate, and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value.

Losses on Purchases or Exchanges of Debt. During the Prior Quarter, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. We recognized a loss of $19 million in the Prior Quarter associated with the redemption.

Also during the Prior Quarter, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 million in the Prior Quarter.

Impairment of Investments. In the Prior Quarter, we recorded impairments of $16 million related to certain equity investments.

Other Income. Other income was $4 million in the Current Quarter and $17 million in the Prior Quarter. The Current Quarter consisted of $4 million of miscellaneous income. The Prior Quarter included $4 million of interest income and $13 million of miscellaneous income.

Income Tax Expense. Chesapeake recorded income tax expense of $589 million in the Current Quarter compared to income tax expense of $349 million in the Prior Quarter. Of the $240 million increase in income tax expense recorded in the Current Quarter, $233 million was the result of the increase in net income before income taxes and $7 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 Nine Months Ended September 30, 2011 vs. September 30, 2010

General. For the Current Period, Chesapeake had net income of $1.269 billion, or $1.69 per diluted common share, on total revenues of $8.908 billion. This compares to net income of $1.550 billion, or $2.24 per diluted common share, on total revenues of $7.391 billion during the Prior Period. The Current Period included a net unrealized after-tax mark-to-market loss of $271 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 $4.688 billion compared to $4.698 billion in the Prior Period. In the Current Period, Chesapeake produced and sold 863.3 bcfe at a weighted average price of $5.94 per mcfe, compared to 766.6 bcfe produced and sold in the Prior Period at a weighted average price of $6.17 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of ($444) million and ($29) 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 $193 million and increased production resulted in a $597 million increase, for a total increase in revenues of $404 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 $5.10 compared to $5.69 in the Prior Period (weighted average prices exclude the effect of unrealized gains or losses on derivatives). In the Current Period and the Prior Period, realized prices of natural gas include 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 September 30, 2011. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $63.80 and $62.75 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 $1.240 billion, or $1.43 per mcfe, in the Current Period and a net increase of $1.484 billion, or $1.94 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 $73 million and $71 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 $22 million and $21 million, respectively, without considering the effect of hedging activities.

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

	Nine Months Ended September 30, 2011						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	294.5	3.41			294.5	34	3.41
Mid-Continent	168.8	3.89	14.9	65.52	258.2	30	6.32
Barnett Shale[c]	91.8	1.61	0.7	37.34	96.0	11	1.82
Marcellus Shale	78.2	3.75	0.9	57.55	83.6	10	4.11
Permian and Delaware Basins	26.6	3.69	3.5	81.97	47.6	6	8.11
Fayetteville Shale	35.9	2.80			35.9	4	2.80
Eagle Ford Shale	3.4	2.61	1.3	70.49	11.2	1	9.02
Rockies/Williston Basin	0.4	4.40	0.2	84.14	1.6		11.38
Other	32.3	3.13	0.4	72.86	34.7	4	3.73
Total[d]	731.9	3.30	21.9	67.53	863.3	100	4.51

	Nine Months Ended September 30, 2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Haynesville/Bossier Shales	162.2	3.75			162.2	21	3.75
Mid-Continent	172.6	4.25	9.6	55.08	230.4	31	5.48
Barnett Shale[c]	148.0	2.60	0.5	29.36	151.0	20	2.64
Marcellus Shale	33.5	4.27	0.1	38.51	34.1	4	4.29
Fayetteville Shale	100.8	3.35			100.8	13	3.35
Permian and Delaware Basins	34.3	4.29	2.0	73.60	46.3	6	6.38
Eagle Ford Shale	0.6	4.85	0.2	72.32	1.8		9.41
Rockies/Williston Basin	0.4	3.23	0.1	69.02	1.0		7.14
Other	37.2	3.92	0.3	68.84	39.0	5	4.29
Total	689.6	3.63	12.8	57.57	766.6	100	4.23

(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. Additionally, the rapid development of the Barnett Shale required the construction of new pipelines to provide an adequate market for these new gas reserves. In order to support the timely construction of these new pipelines, we entered into firm transportation contracts that obligate the company to pay demand fees if we do not deliver specified volumes of natural gas into certain gathering systems and intrastate pipelines. The demand fees associated with unused capacity and the other gathering and transportation fees described above have resulted in lower natural gas price realizations in the Barnett Shale.

(d) The Current Period production reflects the sale of all of our Fayetteville Shale assets, which closed in March 2011 and various other asset sales, including VPP #6, VPP #7, VPP #8 and VPP #9, which closed in February 2010, June 2010, September 2010 and May 2011, respectively.

Our average daily production of 3.162 bcfe for the Current Period consisted of 2.681 bcf of natural gas and 80,253 bbls of liquids. Our Current Period production of 863.3 bcfe consisted of 731.9 bcf of natural gas (85% on a natural gas equivalent basis) and 21.9 mmbbls of liquids (15% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 6% and our year-over-year growth rate of liquids production was 71%. Our percentage of revenue from liquids in the Current Period was 38% of unhedged natural gas and oil revenue compared to 23% in the Prior Period.

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression sales and expenses consist of third-party revenue and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $3.844 billion in marketing, gathering and compression sales in the Current Period with corresponding expenses of $3.744 billion, for a net margin before depreciation of $100 million. This compares to sales of $2.520 billion, expenses of $2.429 billion and a net margin before depreciation of $91 million in the Prior Period. In the Current Period, Chesapeake realized an increase in marketing, gathering and compression sales and expenses primarily due to an increase in third-party marketing, gathering and compression volumes.

Oilfield Services Revenue and Expenses. Oilfield services consists of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $376 million in oilfield services revenue in the Current Period with corresponding expense of $287 million, for a net margin before depreciation of $89 million. This compares to revenue of $173 million, expenses of $154 million and a net margin before depreciation of $19 million in the Prior Period. Oilfield services margins have increased as service rates increased throughout 2010 and 2011 in addition to an increase in services provided to third parties.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $782 million in the Current Period and $652 million in the Prior Period. On a unit-of-production basis, production expenses were $0.91 per mcfe in the Current Period compared to $0.85 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 $140 million in the Current Period compared to $119 million in the Prior Period. On a unit-of-production basis, production taxes were $0.16 per mcfe in both the Current Period and 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 $21 million increase in production taxes in the Current Period is primarily due to a decrease in the average sales price of natural gas and oil of $0.28 per mcfe (excluding gains or losses on derivatives) and an increase in production of 97 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 $410 million in the Current Period and $340 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 $0.47 and $0.44 per mcfe for the Current Period and Prior Period, respectively. Included in general and administrative expenses is stock-based compensation of $71 million for the Current Period and $63 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 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, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, drilling and completion 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 $327 million and $287 million of internal costs in the Current Period and the

Prior Period, respectively, directly related to our natural gas and oil property acquisition, drilling and completion efforts and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas and oil properties was $1.147 billion and $1.025 billion during the Current Period and the Prior Period, respectively. The $122 million increase is primarily the result of a 13% 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 $1.33 and $1.34 in the Current Period and in the Prior Period, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $206 million in the Current Period and $159 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 drilling and completion costs.

Losses on Sales of Other Property and Equipment. Losses on sales of other property, plant and equipment were $3 million in the Current Period and $17 million in the Prior Period. These losses were related to the sales of pipe, gas gathering systems and other miscellaneous assets.

Other Impairments. In the Current Period, we recorded a $4 million charge for impairments of certain fixed assets. In the Prior Period, we recorded a $20 million impairment charge related to obsolete pipe inventory.

Interest Expense. Interest expense was $37 million in the Current Period compared to $12 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2011	2010
	($ in millions)	
Interest expense on senior notes	$ 494	$ 550
Interest expense on credit facilities	49	42
Realized (gain) loss on interest rate derivatives	6	(6)
Unrealized (gain) loss on interest rate derivatives	13	(75)
Amortization of loan discount and other	30	26
Capitalized interest	(555)	(525)
Total interest expense	$ 37	$ 12
Average long-term borrowings	$ 9,445	$ 10,538

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.03 per mcfe in the Current Period compared to $0.11 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 $30 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 on Investments. Earnings on investments were $100 million and $190 million in the Current Period and the Prior Period, respectively. The Current Period includes $39 million of additional earnings from our Frac Tech investment compared to the Prior Period. The Prior Period included a $121 million gain related to the initial public offering by CHKM and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value.

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. Also during the Prior Period, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. We recognized a loss of $19 million in the Prior Period associated with the redemption.

Additionally during the Prior Period, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 million in the Prior Period.

Finally, 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.

Impairment of Investments. In the Prior Period, we recorded impairments of $16 million related to certain equity investments.

Other Income. Other income was $9 million in the Current Period and $12 million in the Prior Period. The Current Period consisted of $1 million of interest income and $8 million of miscellaneous income. The Prior Period included $7 million of interest income and $5 million of miscellaneous income.

Income Tax Expense. Chesapeake recorded income tax expense of $812 million in the Current Period compared to income tax expense of $970 million in the Prior Period. Of the $158 million decrease in income tax expense recorded in the Current Period, $169 million was the result of the decrease in net income before income taxes which was partially offset by a $11 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 September 2011, the FASB issued guidance related to the annual goodwill impairment test. The guidance provides entities with the option of performing a qualitative assessment to determine whether the two-step goodwill impairment test is necessary. The revised standard is effective for goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We do not expect this guidance to have a material effect on our financial condition or results of operations as it is a change in application of the goodwill impairment test only.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements and requires certain other disclosures. We are evaluating the impact of this guidance, which will be adopted effective January 1, 2012.

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 under 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 discussion regarding fair value measurements.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). Forward-looking statements give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned 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.

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 trade that effectively reverses the current position (a counter-trade). 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.

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

	Volume (bbtu)	Weighted Average Price (per mmbtu) Fixed	Put	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Natural Gas:							
Call Options:							
Q1 2012	40,049	$	$	$ 6.54	$	No	$
Q2 2012	40,049			6.54		No	
Q3 2012	40,489			6.54		No	(2)
Q4 2012	40,489			6.54		No	(3)
2013	415,046			6.44		No	(75)
2014	330,183			6.43		No	(115)
2015	200,349			6.35		No	(120)
2016 2020	392,631			7.93		No	(239)
Put Options:							
Q4 2011	(16,560)		5.48			No	(27)
Basis Protection Swaps (Non-Appalachian Basin):							
Q4 2011	6,546				(0.82)	No	(5)
Q1 2012	1,820				(0.35)	No	
Q2 2012	20,174				(0.81)	No	(12)
Q3 2012	20,427				(0.80)	No	(12)
Q4 2012	8,111				(0.74)	No	(4)
2013	7,300				(0.35)	No	(1)
2014 2018	22,049				(0.81)	No	(11)
Basis Protection Swaps (Appalachian Basin):							
Q4 2011	12,324				0.14	No	1
2012 2022	134				0.11	No	
	Total Natural Gas						$ (625)

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	Volume (mbbl)	Fixed	Weighted Average Price Put	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
			(per bbl)				
Oil:							
Non-Qualified Swaps:							
Q4 2011	163	$ 84.37	$	$	$	No	$
Q1 2012	165	84.99				No	1
Q2 2012	167	85.72				No	1
Q3 2012	176	86.40				No	1
Q4 2012	184	86.98				No	1
2013	740	87.69				No	3
2014 2015	1,213	88.47				No	4
Call Options[a]:							
Q4 2011	2,300			95.81		No	(11)
Q1 2012	4,502			93.73		No	(18)
Q2 2012	4,502			93.73		No	(23)
Q3 2012	4,552			93.73		No	(30)
Q4 2012	4,552			93.73		No	(32)
2013	17,655			89.44		No	(197)
2014	11,799			90.94		No	(145)
2015	18,082			99.20		No	(199)
2016 2017	21,299			96.61		No	(291)
Knock-Out Swaps:							
Q4 2011	276	104.75	60.00			No	7
Q1 2012	182	109.50	60.00			No	4
Q2 2012	182	109.50	60.00			No	3
Q3 2012	184	109.50	60.00			No	3
Q4 2012	184	109.50	60.00			No	3
	Total Oil						$ (915)
	Total Natural Gas and Oil						$ (1,540)

(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.

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In addition to the open derivative positions disclosed above, at September 30, 2011, we had $709 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.

	September 30, 2011 ($ in millions)
Q4 2011	358
Q1 2012	139
Q2 2012	170
Q3 2012	3
Q4 2012	(17)
2013	60
2014	(191)
2015	159
2016 2022	28
Total	$ 709

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 $1.540 billion fair value liability as of September 30, 2011, ($119) million related to contracts maturing in the next 12 months and ($1.421) billion related to contracts maturing after 12 months. All transactions hedged as of September 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	879
Fair value of new contracts when entered into	(399)
Contracts realized or otherwise settled	(521)
Fair value of contracts when closed	(850)
Fair value of contracts outstanding, as of September 30	$ (1,540)

The change in natural gas and oil prices during the Current Period decreased the value of our derivative liabilities by $879 million. This gain 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 $399 million. We settled contracts for $521 million and we closed out contracts that were in an asset position for $850 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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ in millions)			
Natural gas and oil sales	$ 1,427	$ 1,074	$ 3,892	$ 3,243
Realized gains (losses) on natural gas and oil derivatives	344	512	1,240	1,484
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	636	48	(457)	(9)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(5)	5	13	(20)
Total natural gas and oil sales	$ 2,402	$ 1,639	$ 4,688	$ 4,698

To mitigate our exposure to the fluctuation in prices of diesel fuel, which is used in our exploration and development activities, we have entered into diesel swaps from October 2011 to December 2012 for a total of 60 million gallons with an average fixed price of $2.99 per gallon. Chesapeake pays the fixed price and receives a floating price. The fair value of these swaps as of September 30, 2011 was a liability of $16 million.

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	$ 6,976	$ 8,705
Average interest rate			7.63%		9.5%	5.48%	6.18%
Long-term debt variable rate	$	$	$	$	$ 3,236	$ 327	$ 3,563
Average interest rate					1.98%	2.24%	2.00%

(a) This amount does not include the discount included in long-term debt of ($509) million and interest rate derivatives of $30 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 September 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 September 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:						
Swaption						
Q4 2011	$ 300	6.5%	3 ml plus 297 bp	No	$ 3	$
Floating to Fixed:						
Swaps						
Mature 2014 2015	$ 1,050	2.13%	1 6 mL	No		(46)
					$ 3	$ (46)

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

In addition to the open derivative positions disclosed above, at September 30, 2011 we had $82 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 nine-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 September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	($ in millions)			
Interest expense on senior notes	$ 152	$ 167	$ 494	$ 550
Interest expense on credit facilities	18	18	49	42
Realized (gains) losses on interest rate derivatives		(2)	6	(6)
Unrealized (gains) losses on interest rate derivatives		2	13	(75)
Amortization of loan discount and other	8	3	30	26

Capitalized interest	(174)	(185)	(555)	(525)
Total interest expense	$ 4	$ 3	$ 37	$ 12

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 a liability of $31 million at September 30, 2011. The euro-denominated debt in long-term debt has been adjusted to $463 million at September 30, 2011 using an exchange rate of $1.3449 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.

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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 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 September 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*

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. On September 2, 2010, the court denied defendants motion to dismiss, and on August 1, 2011, the plaintiffs filed a motion for class certification. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action is stayed pursuant to stipulation. A second derivative action relating to the July 2008 offering was filed against certain current and former directors and officers of the company in the U.S. District Court for the Western District of Oklahoma on September 6, 2011. This action also asserts breaches of fiduciary duties with respect to alleged material omissions in the offering registration statement. Chesapeake is named as a nominal defendant in both derivative actions.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging, among other things, breaches of fiduciary duties relating to the 2008 compensation of the company s CEO and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake s motion to dismiss was granted on February 26, 2010, and the Oklahoma Court of Civil Appeals affirmed the dismissal on August 26, 2011. The plaintiffs filed a petition for writ of certiorari with the Oklahoma Supreme Court on September 13, 2011. On November 1, 2011, the company entered into a Stipulation and Agreement of Settlement (the Stipulation) setting forth the terms of a proposed settlement between the parties in this derivative action, as well as in an inspection demand case requesting books and records relating to the company s December 2008 employment agreement with its CEO. The inspection demand case, currently on appeal at the Oklahoma Court of Civil Appeals, was filed initially on March 26, 2009 in the District Court of Oklahoma County, Oklahoma, and the plaintiff s petition for writ of mandate to compel inspection was denied on September 2, 2009. On November 1, 2011, the District Court of Oklahoma County, Oklahoma entered an order preliminarily approving settlement of the two cases in accordance with the Stipulation filed November 1, 2011. The order also approved distribution of a notice of settlement to Chesapeake shareholders and set a hearing date to consider final approval of the settlement for January 30, 2012. The appeals of both the consolidated derivative case and the inspection demand case have been stayed pending court approval of the settlement. The settlement, if approved by the court, will not have a material effect on the company s consolidated financial position, results of operations or cash flows, and the litigation will be dismissed with prejudice against all defendants.

On September 6 and 8, 2011, in separate derivative actions filed in the U.S. District Court for the Western District of Oklahoma against certain of the company s current and former directors, two shareholders have alleged that the company s directors have waived the demand requirement for derivative actions or wrongfully refused their demands that the board take certain actions related to executive compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the company.

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 to you 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.

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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) alleging violations of the state s Oil and Gas Act, Clean Streams Law and Solid Waste Management Act. 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. An independent consulting firm retained by Chesapeake has filed a report with the DEP concluding that were no ecological impacts to nearby tributaries, no impacts to nearby or regional water wells or springs and no subsurface release of fluids or natural gas from the well control incident or from hydraulic well stimulation operations. 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. We are unable to predict at this time the amount of any fines or penalties that may result from this incident.

In addition, there are pending against us two unrelated compliance orders issued by the DEP, each alleging violations of the Pennsylvania Clean Streams Law. One pertains to the construction of a well pad and the other to erosion and sediment control associated with a pad site. We have responded to each of the orders and continue to work with the DEP to resolve the matters. Although we cannot estimate the amount of any monetary sanctions, resolution of each compliance order can reasonably be expected to include monetary sanctions in excess of $100,000.

ITEM 1A. ***Risk Factors***

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under Risk Factors in Item 1A of our 2010 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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ITEM 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***
The following table presents information about repurchases of our common stock during the Current Quarter:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share [(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
July 1, 2011 through July 31, 2011	1,070,125	$ 30.17		
August 1, 2011 through August 31, 2011	1,221,447	$ 29.57		
September 1, 2011 through September 30, 2011	68,975	$ 28.80		
Total	2,360,547	$ 29.82		

(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.

On September 30, 2011, a holder of our 5.75% convertible preferred stock converted 3,000 shares of 5.75% preferred stock into 111,111 shares of common stock at a conversion rate of 37.037 shares of common stock per share of the preferred stock. The issuance of the shares of common stock was exempt from registration under the Securities Act of 1933 pursuant to Section 3(a)(9) under the Securities Act.

ITEM 3. ***Defaults Upon Senior Securities***
Not applicable.

ITEM 4. ***(Removed and Reserved)***

ITEM 5. ***Other Information***
Not applicable.

ITEM 6. ***Exhibits***

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

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.12.1	First Amendment to Eighth Amended and Restated Credit Agreement, dated as of September 19, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.					X	
4.12.2	Second Amendment to Eighth Amended and Restated Credit Agreement, dated as of October 12, 2011, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, the other agents named therein and the several lenders parties thereto.					X	
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	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
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
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: November 9, 2011

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

Chairman of the Board and

Chief Executive Officer

Date: November 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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INDEX TO EXHIBITS

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		
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