CHESAPEAKE ENERGY CORP
Form 10-Q
May 10, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Quarterly Period Ended March 31, 2013
[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to
Commission File No. 1-13726
Chesapeake Energy Corporation
(Exact name of registrant as specified in its charter)

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

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

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

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

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

Large Accelerated Filer [X] Accelerated Filer [ ] Non-accelerated Filer [ ] Smaller Reporting Company [ ]

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

As of May 1, 2013, there were 666,461,015 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
INDEX TO FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2013

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

	March 31, 2013	December 31, 2012
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$33	$287
Restricted cash	81	111
Accounts receivable	2,382	2,245
Short-term derivative assets	5	58
Deferred income tax asset	216	90
Other current assets	156	153
Current assets held for sale	11	4
Total Current Assets	2,884	2,948
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Evaluated natural gas and oil properties ($488 and $488 attributable to our VIE)	51,918	50,172
Unevaluated properties	14,626	14,755
Oilfield services equipment	2,261	2,130
Other property and equipment	3,797	3,778
Total Property and Equipment, at Cost	72,602	70,835
Less: accumulated depreciation, depletion and amortization (($109) and ($58) attributable to our VIEs)	(35,043)	(34,302)
Property and equipment held for sale, net	588	634
Total Property and Equipment, Net	38,147	37,167
LONG-TERM ASSETS:		
Investments	711	728
Long-term derivative assets	2	2
Other long-term assets	737	766
TOTAL ASSETS	$42,481	$41,611

The accompanying notes are an integral part of these condensed consolidated financial statements.
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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS – (Continued)
(Unaudited)

	March 31, 2013	December 31, 2012
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$1,909	$1,710
Short-term derivative liabilities ($6 and $4 attributable to our VIEs)	424	105
Accrued interest	144	226
Current maturities of long-term debt, net	—	463
Other current liabilities ($23 and $21 attributable to our VIEs)	3,288	3,741
Current liabilities held for sale	20	21
Total Current Liabilities	5,785	6,266
LONG-TERM LIABILITIES:		
Long-term debt, net	13,449	12,157
Deferred income tax liabilities	3,021	2,807
Long-term derivative liabilities ($3 and $3 attributable to our VIEs)	693	934
Asset retirement obligations	387	375
Other long-term liabilities	1,132	1,176
Total Long-Term Liabilities	18,682	17,449
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 shares outstanding	3,062	3,062
Common stock, $0.01 par value, 1,000,000,000 shares authorized: 669,274,935 and 666,467,664 shares issued	7	7
Paid-in capital	12,355	12,293
Retained earnings	495	437
Accumulated other comprehensive income (loss)	(170)	(182)
Less: treasury stock, at cost; 2,229,977 and 2,147,724 common shares	(49)	(48)
Total Chesapeake Stockholders' Equity	15,700	15,569
Noncontrolling interests	2,314	2,327
Total Equity	18,014	17,896
TOTAL LIABILITIES AND EQUITY	$42,481	$41,611

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

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

	Three Months Ended March 31,	
	2013	2012
	($ in millions except per share data)	
REVENUES:		
Natural gas, oil and NGL	$1,453	$1,068
Marketing, gathering and compression	1,781	1,216
Oilfield services	190	135
Total Revenues	3,424	2,419
OPERATING EXPENSES:		
Natural gas, oil and NGL production	307	349
Production taxes	53	47
Marketing, gathering and compression	1,745	1,197
Oilfield services	155	96
General and administrative	110	136
Natural gas, oil and NGL depreciation, depletion and amortization	648	506
Depreciation and amortization of other assets	78	84
Net gains on sales of fixed assets	(49)	(2)
Impairments of fixed assets and other	27	—
Employee retirement and other termination benefits	133	—
Total Operating Expenses	3,207	2,413
INCOME FROM OPERATIONS	217	6
OTHER INCOME (EXPENSE):		
Interest expense	(21)	(12)
Losses on investments	(27)	(5)
Impairment of investment	(10)	—
Other income	6	6
Total Other Income (Expense)	(52)	(11)
INCOME (LOSS) BEFORE INCOME TAXES	165	(5)
INCOME TAX EXPENSE (BENEFIT):		
Current income taxes	1	—
Deferred income taxes	62	(2)
Total Income Tax Expense (Benefit)	63	(2)
NET INCOME (LOSS)	102	(3)
Net income attributable to noncontrolling interests	(44)	(25)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	58	(28)
Preferred stock dividends	(43)	(43)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$15	$(71)
EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$0.02	$(0.11)
Diluted	$0.02	$(0.11)
CASH DIVIDEND DECLARED PER COMMON SHARE	$—	$0.0875
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		

Basic	651	642
Diluted	651	642

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

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

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
NET INCOME (LOSS)	$102	$(3)
Other comprehensive income (loss), net of income tax:		
Unrealized gain (loss) on derivative instruments, net of income tax expense (benefit) of ($1) million and $2 million	(1)	4
Reclassification of (gain) loss on settled derivative instruments, net of income tax expense (benefit) of $7 million and ($1) million	12	(2)
Unrealized gain (loss) on investments, net of income tax expense (benefit) of ($3) million and $3 million	(5)	5
Reclassification of impairment of investment, net of income tax expense (benefit) of $4 million and $0	6	—
Other comprehensive income	12	7
COMPREHENSIVE INCOME	114	4
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(44)	(25)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$70	$(21)

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

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

	Three Months Ended March 31, 2013	2012
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$102	$(3)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	726	590
Deferred income tax expense (benefit)	62	(2)
Unrealized losses on derivatives	152	276
Stock-based compensation	32	32
Net gains on sales of fixed assets	(49)	(2)
Impairments of fixed assets and other	27	—
Losses on investments	29	33
Impairment of investment	10	—
Employee retirement and other termination benefits	105	—
Other	(20)	(14)
Changes in assets and liabilities	(252)	(636)
Cash provided by operating activities	924	274
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(1,579)	(2,574)
Acquisitions of proved and unproved properties	(280)	(1,135)
Proceeds from divestitures of proved and unproved properties	190	821
Additions to other property and equipment	(330)	(690)
Proceeds from sales of other assets	201	48
Additions to investments	(3)	(73)
(Increase) decrease in restricted cash	55	(37)
Other	1	(10)
Cash used in investing activities	(1,745)	(3,650)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	3,632	5,688
Payments on credit facilities borrowings	(2,811)	(4,546)
Proceeds from issuance of senior notes, net of discount and offering costs	—	1,263
Cash paid for prepayment of mortgage	(55)	—
Cash paid for common stock dividends	(58)	(56)
Cash paid for preferred stock dividends	(43)	(43)
Cash paid on financing derivatives	(11)	(9)
Proceeds from sales of noncontrolling interests	—	1,044
Proceeds from other financings	—	225
Distributions to noncontrolling interest owners	(57)	(39)
Other	(30)	(64)
Cash provided by financing activities	567	3,463
Net increase (decrease) in cash and cash equivalents	(254)	87
Cash and cash equivalents, beginning of period	287	351

Cash and cash equivalents, end of period	$33	$438

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

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

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Supplemental disclosure of cash flow information of net cash payments (refunds) for:		
Interest, net of capitalized interest	$60	$36
Income taxes, net of refunds received	$—	$—
Supplemental disclosure of significant non-cash investing and financing activities:		
Change in accrued drilling and completion costs	$(79)	$26
Change in accrued acquisition of proved and unproved property costs	$(3)	$(2)
Change in accrued costs for other property and equipment	$11	$24

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

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

	Three Months Ended March 31, 2013	2012
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$3,062	$3,062
COMMON STOCK:		
Balance, beginning and end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,293	12,146
Stock-based compensation	70	33
Reduction in tax benefit from stock-based compensation	(10)	(4)
Exercise of stock options	2	1
Balance, end of period	12,355	12,176
RETAINED EARNINGS:		
Balance, beginning of period	437	1,608
Net income (loss) attributable to Chesapeake	58	(28)
Dividends on common stock	—	(56)
Dividends on preferred stock	—	(43)
Balance, end of period	495	1,481
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(182)	(166)
Hedging activity	11	2
Investment activity	1	5
Balance, end of period	(170)	(159)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(48)	(33)
Purchase of 160,145 and 142,655 shares for company benefit plans	(3)	(3)
Release of 77,892 and 12,834 shares from company benefit plans	2	—
Balance, end of period	(49)	(36)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	15,700	16,531
NONCONTROLLING INTERESTS:		
Balance, beginning of period	2,327	1,337
Sales of noncontrolling interests	—	1,040
Net income attributable to noncontrolling interests	44	25
Distributions to noncontrolling interest owners	(57)	(39)
Balance, end of period	2,314	2,363
TOTAL EQUITY	$18,014	$18,894

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

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). This Form 10-Q relates to the three months ended March 31, 2013 (the “Current Quarter”) and three months ended March 31, 2012 (the “Prior Quarter”). Chesapeake’s annual report on Form 10-K for the year ended December 31, 2012 (2012 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 presentation 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 and entities in which Chesapeake holds a controlling interest. All significant intercompany accounts and transactions have been eliminated. The results for the Current Quarter are not necessarily indicative of the results to be expected for the full year.

Critical Accounting Policies

We consider accounting policies related to variable interest entities, natural gas and oil properties, derivatives 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 2012 Form 10-K.

Risks and Uncertainties

Our business strategy is to continue growing our reserves and production while transitioning from an asset base primarily focused on natural gas to an asset base more balanced between natural gas and liquids production. This is a capital-intensive strategy, and we made capital expenditures in 2012 and the Current Quarter that exceeded our cash flow from operations, filling the gap with borrowings and proceeds from sales of assets that we determined were noncore or did not fit our long-term plans. We project that our capital expenditures will continue to exceed our operating cash flow in 2013, although by a significantly smaller amount. Our 2013 capital expenditure budget is approximately 50% less than our 2012 capital expenditures, and as operator of a substantial portion of our natural gas and oil properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to expeditiously reduce at least a portion of our capital spending if needed. To add certainty to future estimated cash flows by mitigating our downside exposure to lower commodity prices, we currently have downside price protection, in the form of over-the-counter derivative contracts, on approximately 78% of our remaining 2013 estimated natural gas production at an average price of $3.72 per mcf and 88% of our remaining 2013 estimated oil production at an average price of $95.43 per bbl. Hedging allows us to reduce our exposure to price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization). Based on these and other factors, we believe we have adequate borrowing capacity through our current credit arrangements, together with anticipated proceeds from transactions subject to binding agreements to sell assets, to make up the difference between our budgeted capital expenditures and operating cash flow in 2013.

As part of our asset sales planning and capital expenditure budgeting process, we closely monitor the resulting effects on the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our corporate revolving bank credit facility. While asset sales enhance our ability to reduce debt, sales of producing natural gas and oil properties may adversely affect the amount of cash flow and EBITDA we generate and reduce the amount and value of collateral available to secure our obligations, both of which can be exacerbated by low prices received for our production. In September 2012, we obtained an amendment to our corporate revolving bank credit facility agreement that relaxed the required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. Without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance, primarily because the closing of certain asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. Failure to maintain compliance with the covenants of our corporate revolving bank credit facility could result in the acceleration of outstanding indebtedness under the facility and lead to cross defaults under our senior note and contingent convertible senior note indentures, secured hedging facility, equipment master lease agreements, term loan and other agreements. See Note 3 for further discussion of our debt instruments, including the terms of the credit facility amendment. Based on our budgeted capital expenditures, expected commodity prices (including the impact from our derivative contracts), our forecasted drilling and production, projected levels of indebtedness and binding purchase and sale agreements for certain future asset sales, we expect we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility through the 2014 first quarter. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures, to adapt to potential negative developments if needed to maintain covenant compliance.

Natural gas prices reached 10-year lows in 2012, and although our strategic focus on increasing liquids production is progressing and we have derivatives providing downside price protection in place covering approximately 78% of our projected remaining 2013 natural gas production, we continue to have significant exposure to natural gas prices. Approximately 70% of our estimated proved reserves volumes as of December 31, 2012 were natural gas, and natural gas represented approximately 76% and 80% of our natural gas, oil and NGL sales volumes for the Current Quarter and the 2012 full year, respectively. In 2012, we reduced our estimate of proved reserves by 3.1 tcfe, or 17%, primarily due to the impact of downward natural gas price revisions. Natural gas prices used in estimating proved reserves at December 31, 2012, including the effect of price differential adjustments, decreased by 45% from $3.19 per mcf to $1.75 per mcf, causing the loss of significant proved undeveloped reserves for which future development is uneconomic. As a result of lower estimated reserves, in the 2012 third quarter, we were required to impair the carrying value of our natural gas and oil properties, and we could have additional impairments in the future.

We believe we have taken appropriate measures to mitigate the risks and uncertainties facing us in 2013. Nevertheless, our ability to generate operating cash flow and complete asset sales in order to manage debt is subject to all the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. We do not have binding agreements for all of our planned asset sales, and our ability to consummate each of these transactions is subject to changes in market conditions and other factors beyond our control. If one or more of the transactions are not completed in the anticipated time frame, or at all, or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness could be adversely affected. Future impairments of the carrying value of our natural gas and oil properties, if any, will be dependent on many factors, including natural gas, oil and NGL prices, production rates, levels of reserves, the evaluation of costs excluded from amortization, the timing and impact of asset sales, future development costs and service costs.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Assets and Liabilities Held for Sale
We are currently pursuing sales of the majority of our remaining natural gas gathering business which we expect to complete in the 2013 second quarter. The natural gas gathering business qualified as held for sale as of March 31, 2013 and December 31, 2012 and is reported under our marketing, gathering and compression operating segment. In addition, we are pursuing the sale, within the next 12 months, of various other property and equipment, including land and buildings primarily in the Fort Worth, Texas area. The land and buildings are reported under our other operating segment. Natural gas and oil properties that we intend to sell are not presented as held for sale pursuant to the rules governing full cost accounting for oil and gas properties. We are also continuing to review our portfolio of other noncore assets, including real estate and other holdings in Oklahoma City (other than our core campus), and we may determine to divest all or a portion of these assets in subsequent periods. A summary of the assets and liabilities held for sale on our condensed consolidated balance sheets as of March 31, 2013 and December 31, 2012 is detailed below.

	March 31, 2013	December 31, 2012
	($ in millions)	
Accounts receivable	$11	$4
Current assets held for sale	$11	$4
Natural gas gathering systems and treating plants, net of accumulated depreciation	$330	$352
Oilfield services equipment, net of accumulated depreciation[a]	—	27
Other property and equipment, net of accumulated depreciation	258	255
Property and equipment held for sale, net	$588	$634
Accounts payable	$—	$4
Accrued liabilities	20	17
Current liabilities held for sale	$20	$21

(a) In the Current Quarter, we sold eight rigs classified as assets held for sale as of December 31, 2012 for proceeds of approximately $27 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Accumulated Other Comprehensive Income (Loss)

For the Current Quarter, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
	($ in millions)		
Balance, December 31, 2012	$(189)	$7	$(182)
Other comprehensive income before reclassifications	(1)	(5)	(6)
Amounts reclassified from accumulated other comprehensive income	12	6	18
Net current period other comprehensive income	11	1	12
Balance, March 31, 2013	$(178)	$8	$(170)

For the Current Quarter, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the condensed consolidated statement of operations are detailed below.

Details About Accumulated Other Comprehensive Income Components	Affected Line Item in the Statement Where Net Income is Presented	Amount Reclassified from Accumulated Other Comprehensive Income
		($ in millions)
Net losses on cash flow hedges:		
Commodity contracts	Natural gas, oil and NGL revenues	$12
Investments:		
Impairment of investment	Impairment of investment	6
Total reclassifications for the period, net of tax		$18

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

2. Net Income Per Share

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

For the Current Quarter and the Prior Quarter, the contingent convertible senior notes did not have a dilutive effect and therefore were not included in the calculation of diluted EPS. See Note 3 for discussion of the contingent convertible senior notes.

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

	Net Income Adjustments ($ in millions)	Shares (in millions)
Three Months Ended March 31, 2013:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$22	56
5.75% cumulative convertible preferred stock (series A)	$16	39
5.00% cumulative convertible preferred stock (series 2005B)	$3	5
4.50% cumulative convertible preferred stock	$3	6
Three Months Ended March 31, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$22	55
5.75% cumulative convertible preferred stock (series A)	$16	39
5.00% cumulative convertible preferred stock (series 2005B)	$3	5
4.50% cumulative convertible preferred stock	$3	6
Unvested restricted stock	$—	4
Outstanding stock options	$—	1

Basic weighted average shares outstanding, which is used in computing basic EPS, and diluted weighted average shares outstanding, which is used in computing diluted EPS, were 651 million shares in the Current Quarter and 642 million shares in the Prior Quarter, respectively. The basic and diluted earnings per common share were $0.02 in the Current Quarter and the basic and diluted loss per common share was $0.11 in the Prior Quarter.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

3. Debt

Our long-term debt consisted of the following as of March 31, 2013 and December 31, 2012:

	March 31, 2013	December 31, 2012
	($ in millions)	
Term loan due 2017	$2,000	$2,000
7.625% senior notes due 2013[(a)]	464	464
9.5% senior notes due 2015	1,265	1,265
6.25% euro-denominated senior notes due 2017[(b)]	440	454
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018[(a)]	474	474
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[(c)]	650	650
6.775% senior notes due 2019[(d)]	1,300	1,300
6.625% senior notes due 2020	1,300	1,300
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	1,000
2.75% contingent convertible senior notes due 2035[(e)]	396	396
2.5% contingent convertible senior notes due 2037[(e)]	1,168	1,168
2.25% contingent convertible senior notes due 2038[(e)]	347	347
Corporate revolving bank credit facility	832	—
Oilfield services revolving bank credit facility	408	418
Discount on senior notes and term loan[(f)]	(441)	(465)
Interest rate derivatives[(g)]	17	20
Total debt, net	13,449	12,620
Less current maturities of long-term debt, net[(a)]	—	(463)
Total long-term debt, net	$13,449	$12,157

(a) See Note 18 for further discussion of tender offers completed for a portion of these notes subsequent to March 31, 2013. We reclassified our 7.625% Senior Notes due 2013 from current liabilities to long-term debt as of March 31, 2013 as we refinanced these notes on a long-term basis subsequent to March 31, 2013. There is $1 million of discount associated with the 7.625% Senior Notes due 2013.

(b) The principal amount shown is based on the exchange rate of $1.2816 to €1.00 and $1.3193 to €1.00 as of March 31, 2013 and December 31, 2012, respectively. See Note 7 for information on our related foreign currency derivatives.

(c) Issuers are Chesapeake Oilfield Operating, L.L.C. (COO), an indirect wholly owned subsidiary of the Company, and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(d) In the Current Quarter, we issued notice to the trustee to redeem our 6.775% Senior Notes due 2019 at par. See Note 18 for further discussion.

(e) 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

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specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. In the first quarter of 2013, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the second quarter of 2013 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. During the Current Quarter, the notes were not convertible under this provision. 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	$48.31	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$63.93	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$107.01	June 14, 2019

(f) Discount as of March 31, 2013 and December 31, 2012 included $359 million and $376 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method. Also included $37 million and $40 million of discount as of March 31, 2013 and December 31, 2012, respectively, associated with our November 2012 term loan.

(g) See Note 7 for further discussion related to these instruments.

Term Loan

November 2012 Term Loan. In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion (November 2012 term loan). Our obligations under the facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the facility bear interest at our option, at either (i) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin of 4.50% or (ii) a base rate equal to the greater of (a) the Bank of America, N.A. prime rate, (b) the federal funds effective rate plus 0.50% per annum and (c) the Eurodollar rate that would be applicable to a Eurodollar loan with an interest period of one month plus 1% per annum, in each case, plus a margin of 3.50%. The Eurodollar rate is subject to a floor of 1.25% per annum, and the base rate is subject to a floor of 2.25% per annum. Interest is payable quarterly or, if the Eurodollar rate applies, it may be payable at more frequent intervals.

The November 2012 term loan matures on December 2, 2017 and may be voluntarily repaid at a make-whole price in the first year, may be voluntarily repaid in the second and third years at par plus a specified call premium and may be voluntarily repaid at any time thereafter at par. The term loan may also be refinanced or amended to extend the maturity date at our option, subject to lender approval.

The November 2012 term loan credit agreement contains negative covenants substantially similar to those contained in the Company's corporate revolving bank credit facility, including covenants that limit our ability to incur indebtedness, grant liens, make investments, loans and restricted payments and enter into certain business combination transactions. Other covenants include additional restrictions regarding the incurrence of certain unsecured indebtedness, the incurrence of secured indebtedness, the disposition of assets and the prepayment of certain indebtedness. The term loan credit agreement does not contain financial maintenance covenants.

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We were in compliance with all covenants under the November 2012 term loan credit agreement as of March 31, 2013. If we should fail to perform our obligations under the agreement, the term loan could be terminated and any outstanding borrowings under the term loan credit agreement could be declared immediately due and payable. The term loan credit 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.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured 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. Chesapeake’s obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries. Certain of our oilfield services subsidiaries and subsidiaries formed to invest in natural gas demand initiatives, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain de minimis subsidiaries are not guarantors. See Note 16 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 may limit our ability and our subsidiaries’ ability to incur certain secured indebtedness, enter into sale/leaseback transactions, and consolidate, merge or transfer assets. The indentures governing the contingent convertible senior notes do not have any financial or restricted payment covenants. The senior notes and contingent convertible senior notes indentures have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of $50 million or $75 million, depending on the indenture.

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

During the Prior Quarter, we issued $1.3 billion of 6.775% Senior Notes due 2019 in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility. On March 15, 2013, we provided notice to the trustee of our election to redeem the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest on May 13, 2013. See Note 18 for further discussion of litigation related to the redemption of these notes.

The $464 million aggregate principal amount of our 7.625% senior notes, which is due in July 2013, was partially refinanced on a long-term basis subsequent to March 31, 2013 and the remaining balance will be repaid and/or retired upon maturity. No other scheduled principal payments are required on our senior notes until 2015. See Note 18 for further discussion of tender offers for certain series of our senior notes completed subsequent to March 31, 2013.

COO Senior Notes

In October 2011, our wholly owned subsidiaries, Chesapeake Oilfield Operating, L.L.C. (COO) and Chesapeake Oilfield Finance, Inc., issued $650 million principal amount of 6.625% Senior Notes due 2019 in a private placement. COO used the net proceeds of approximately $637 million from the placement to make a cash distribution to its direct parent, COS Holdings, L.L.C. (COS), to enable it to reduce indebtedness under an intercompany note with Chesapeake. Chesapeake then used the cash distribution to reduce indebtedness under its corporate revolving bank credit facility.

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO’s other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO's wholly owned subsidiaries, other than de minimis subsidiaries. The notes may be redeemed at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur

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indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets. The COO senior notes have cross default provisions that apply to other indebtedness COO or any of its guarantor subsidiaries may have from time to time with an outstanding principal amount of $50 million or more.

Under a registration rights agreement, we agreed to file a registration statement enabling holders of the COO senior notes to exchange the privately placed COO senior notes for publicly registered notes with substantially the same terms. We filed the registration statement on April 5, 2013. We are required to use our commercially reasonable best efforts to cause the registration statement to become effective as soon as practicable after filing and to consummate the exchange offer on the earliest practicable date after such date, but in no event later than 60 days after the date the registration statement has become effective.

Bank Credit Facilities

During the Current Quarter, we used two revolving bank credit facilities as sources of liquidity. In addition, in the Prior Quarter, we utilized a midstream credit facility. In June 2012, we paid off and terminated our midstream credit facility. Our remaining revolving bank credit facilities are described below.

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of March 31, 2013	$832	$408
Letters of credit outstanding as of March 31, 2013	$31	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower is COO.

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 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 LIBOR, plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. These margins may be increased pursuant to the terms of the credit facility amendment discussed below. 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. In September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. See Risks and Uncertainties in Note 1 for further discussion. The amendment, among other things, adjusts our required indebtedness to EBITDA ratio as set forth below through the earlier of (i) December 31, 2013 and (ii) the date on which we elect to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the “Amendment Effective Period”). The amendment increased the maximum indebtedness to EBITDA ratio as of September 30, 2012 from 4.00 to 1.00 to 6.00 to 1.00 and revises the required ratio for the next four quarters as shown below. The ratio returns to 4.00 to 1.00 as of December 31, 2013 and thereafter.

Effective Date	Amended Indebtedness to EBITDA Ratio
December 31, 2012	5.00 to 1.00
March 31, 2013	4.75 to 1.00
June 30, 2013	4.50 to 1.00
September 30, 2013	4.25 to 1.00

The credit facility amendment increases the applicable margin by 0.25% for borrowings under the corporate credit facility on each day during the Amendment Effective Period when credit extensions exceed 50% of the borrowing capacity and requires us to pay a fee to each lender in an amount equal to 0.05% of its revolving commitment in the event that the Amendment Effective Period is in effect on June 30, 2013. Based on current commitment levels, this would result in an additional payment of $2 million. The amendment does not allow our collateral value securing the borrowings to be more than $75 million below the collateral value that was in effect as of September 30, 2012 during the Amendment Effective Period. We were in compliance with all covenants under the amended agreement as of March 31, 2013.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries. If we should fail to perform our obligations under the agreement, 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 and contingent convertible senior note indentures, which could in turn result in the acceleration of a significant portion of such indebtedness. The credit facility agreement also has cross default provisions that apply to our secured hedging facility, equipment master lease agreements, term loan and other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million. In addition, the facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the oilfield services credit facility are secured by all of the assets of the wholly owned subsidiaries of COO, itself an indirect wholly owned subsidiary of Chesapeake. The facility has initial commitments of $500 million and may be expanded to $900 million at COO’s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, which are unrestricted subsidiaries under Chesapeake’s senior notes, contingent convertible senior notes, term loan and corporate revolving bank credit facility), 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%, or 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

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to earnings before interest, taxes, depreciation, amortization and rent (EBITDAR), a senior secured leverage ratio based on the ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of EBITDAR to lease adjusted interest expense, in each case as defined in the agreement. COO was in compliance with all covenants under the agreement as of March 31, 2013. If COO or its restricted subsidiaries should fail to perform their obligations under the agreement, 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 COO senior note indenture, which could in turn result in the acceleration of the COO senior note indebtedness. 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.

Midstream Credit Facility. Prior to June 15, 2012, we utilized a $600 million syndicated senior secured revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. With the sale of a substantial portion of our midstream business in the second half of 2012, on June 15, 2012, we paid off and terminated our midstream credit facility.

4. Contingencies and Commitments

Contingencies

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek an indeterminate amount of damages. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.

July 2008 Common Stock Offering. 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 the court certified the class on March 30, 2012. Defendants moved for summary judgment on grounds of loss causation and materiality on December 16, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013.

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. On October 22, 2012, the court issued an order staying the derivative action until resolution of the federal class action. On May 3, 2013, the derivative action was dismissed pursuant to the parties’ joint stipulation of dismissal without prejudice. 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. On November 30, 2011, the Company filed a motion to dismiss the action, which was denied on September 28, 2012.

Pursuant to court order, nominal defendant Chesapeake filed an answer on October 12, 2012. By stipulation between the parties, the individual defendants are not required to answer the complaint unless and until the plaintiff establishes standing to pursue claims derivatively.

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2008 CEO Compensation and Related Party Transaction. 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 former CEO, Aubrey K. McClendon, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition naming Chesapeake as a nominal defendant was filed on June 23, 2009. 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. The appeal is currently stayed pending resolution of the settlement referenced in the following paragraph.

On January 30, 2012, the District Court of Oklahoma County, Oklahoma approved a settlement between the parties in the consolidated derivative action, as well as a case on appeal at the Oklahoma Court of Civil Appeals requesting inspection of Company books and records relating to the December 2008 employment agreement with Mr. McClendon. The principal terms of the settlement include the rescission of the sale of an antique map collection that occurred in December 2008 between Mr. McClendon and the Company, whereby Mr. McClendon will pay the Company approximately $12 million plus interest and the Company will reconvey the map collection to Mr. McClendon, and the adoption and/or implementation of a variety of corporate governance measures. The court awarded attorney fees and expenses to plaintiffs' counsel in the amount of $3.75 million. Pursuant to the settlement, the consolidated derivative action and books and records action were dismissed with prejudice against all defendants. On February 29, 2012, certain shareholders filed a petition in error with the Oklahoma Supreme Court opposing the terms of the settlement. Their appeal was fully briefed as of October 24, 2012.

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 alleged that the Chesapeake Board wrongfully refused their demands to investigate purported breaches of fiduciary duties relating to Mr. McClendon's 2008 compensation and, as a result, each of these shareholders asserts he is entitled to seek relief on behalf of the Company. These federal derivative actions were consolidated on December 23, 2011 and on March 14, 2012 were stayed until 30 days after the Supreme Court of Oklahoma resolves the appeal of the settlement of the consolidated derivative action and books and records action.

FWPP, Conflict of Interest and Other Matters. From April 19 to June 29, 2012, 13 substantially similar shareholder derivative actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company and its directors alleging, among other things, violations of Section 14 of the Securities Exchange Act of 1934 and Rule 14a-9 promulgated thereunder for purported material misstatements in the Company's 2009 and subsequent proxy statements related to Mr. McClendon's participation in the Founder Well Participation Program (FWPP) and breaches of fiduciary duties, corporate waste, and unjust enrichment against the Board for failing to make proper disclosures in the proxy statements and failing to properly monitor Mr. McClendon's personal use of assets acquired pursuant to the FWPP. As previously disclosed, in conjunction with Mr. McClendon's employment agreement with the Company, the FWPP provides Mr. McClendon a contractual right through June 2014 to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company's leasehold. On July 13, 2012, these 13 shareholder actions were consolidated into a single case. On April 27, 2012, a shareholder derivative action was filed in the District Court of Oklahoma County, Oklahoma setting forth substantially similar claims to those alleged in the federal shareholder actions. The plaintiffs in both the federal consolidated derivative action and the state court derivative action stipulated to stay their cases pending a ruling on the motion to dismiss filed in the federal securities class action described in the following paragraph. On November 9, 2012, a shareholder derivative suit was filed in the District Court of Oklahoma County, Oklahoma asserting claims substantially similar to those of the stayed derivative cases, but also asserting that the shareholder had derivative standing because the Board had wrongfully refused his litigation demand made in August 2012. Chesapeake moved to dismiss for lack of derivative standing, and on April 18, 2013 the motion to dismiss was granted. On February 6, 2013, another shareholder derivative suit was filed in the

District Court of Oklahoma County, Oklahoma asserting claims substantially similar to those of the stayed derivative cases and seeking a temporary restraining order barring the Company from providing Mr. McClendon severance compensation and benefits. The request for the restraining order was denied March 28, 2013. Chesapeake filed a motion to dismiss the case for the plaintiff's lack of derivative standing and briefing was completed on April 19, 2013. A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and Mr. McClendon alleging violations of Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserted claims under Sections 10(b) (and Rule 10b-5) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company's asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon's personal loans and the Company's internal controls. The action sought class certification, damages of an unspecified amount and attorneys' fees and other costs. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. The Court granted the motion and dismissed the complaint with prejudice on April 10, 2013.

On June 19, July 17 and July 20, 2012, putative class actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company, Chesapeake Energy Savings and Incentive Stock Bonus Plan (the Plan), and certain of the Company's officers and directors alleging breaches of fiduciary duties under the Employee Retirement Income Security Act (ERISA). The actions are brought on behalf of participants and beneficiaries of the Plan, and allege that as fiduciaries of the Plan, defendants owed fiduciary duties, which they purportedly breached by, among other things, failing to manage and administer the Plan's assets with appropriate skill and care, and engaging in activities that were in conflict with the best interest of the Plan. The plaintiffs seek class certification, damages of an unspecified amount, equitable relief, and attorneys' fees and other costs. The three cases have been consolidated and a consolidated amended complaint was filed on February 21, 2013. The defendants filed a motion to dismiss on April 22, 2013. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

On May 2, 2012, Chesapeake and Mr. McClendon received notice from the U.S. Securities and Exchange Commission that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry is continuing as an investigation and it has issued subpoenas for information and testimony. The Company is providing information to the SEC in connection with this matter. The Company is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations.

Director and Officer Use of Company Aircraft. On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company's directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company's officers and directors' use of the Company's fractionally owned corporate jets. Chesapeake was named a nominal defendant in the derivative action. On August 21, 2012, the District Court granted the Company's motion to dismiss the case. On December 6, 2012, the plaintiff filed an amended petition in error with the Oklahoma Supreme Court, and on December 26, 2012 nominal defendant/appellee Chesapeake filed its response. The appeal is currently before the Oklahoma Court of Appeals by appointment of the Supreme Court.

Antitrust Investigations. On June 29, 2012, Chesapeake received a subpoena from the Antitrust Division, Midwest Field Office of the U.S. Department of Justice. The subpoena requires the Company to produce certain documents before a grand jury in the Western District of Michigan, which is conducting an investigation into possible violations of antitrust laws in connection with the purchase and lease of oil and gas rights. The Company has also received demands for documents and information from certain state governmental agencies in connection with other investigations relating to the Company's purchase and lease of oil and gas rights. Chesapeake has been providing information in response to these investigations. Chesapeake's Board of Directors commenced its own investigation of these allegations in June 2012 and in February 2013 announced its conclusion that the Company did not violate antitrust laws in connection with the acquisition of Michigan oil and gas rights in 2010.

Business Operations. Chesapeake is 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 contract actions, 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. Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating 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.

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Environmental Risk

The nature of the natural gas and oil business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, procedures, training and auditing to reduce and mitigate such environmental risks. Chesapeake conducts periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are set for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions and divestitures by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and addressing the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition, or agree to assume liability for the remediation of the property.

There are presently pending against our subsidiary, Chesapeake Appalachia, L.L.C. (CALLC), orders for compliance first initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these and similar matters. For one site subject to an EPA order for compliance, CALLC pled guilty in 2012 to three misdemeanor counts of unauthorized discharge of dredged or fill materials into a water of the U.S. We have paid the applicable fine in full, our restoration of the site has been completed and approved by the government, and we believe that we are in compliance with the terms of probation.

The CWA provides authority for significant civil penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers. CWA civil penalties can be as high as $37,500 per day, per violation. The CWA sets forth subjective criteria, including degree of fault and history of prior violations, that influence CWA penalty assessments, and the EPA may also seek to recover the economic benefit derived from non-compliance. While we expect that resolution of the EPA’s orders for compliance will include monetary sanctions exceeding $100,000, we believe the liability with respect to these matters will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

Commitments

Rig Leases

In a series of transactions beginning in 2006, our drilling subsidiary sold 94 drilling rigs (of which 26 rigs have been repurchased) and related equipment 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 commitments are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related net gains are amortized to oilfield services expenses 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 a lease for negotiated new terms at the expiration of the lease. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2013, the minimum aggregate undiscounted future rig lease payments were approximately $282 million.

Chesapeake has contracts with various drilling contractors to utilize approximately 18 rigs with terms ranging from one year to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2013, the aggregate undiscounted minimum future payments under these drilling rig commitments were approximately $145 million.

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Compressor Leases
Through various transactions beginning in 2007, our compression subsidiary sold 2,558 compressors (of which 238 units have been repurchased), a significant portion of its compressor fleet, and entered into a master lease agreement under which we agreed to lease the compressors from the buyer for initial terms of four to ten years. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks, and any related net gains are 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 a lease for negotiated new terms at the expiration of the lease. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of March 31, 2013, the minimum aggregate undiscounted future compressor lease payments were approximately $384 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 and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying condensed consolidated balance sheets; however, they are reflected as adjustments to future natural gas, oil and NGL sales prices used in our proved reserves estimates.
The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, are presented below.

	March 31, 2013 ($ in millions)
2013	$1,215
2014	1,991
2015	1,810
2016	1,904
2017	1,931
2018 - 2099	9,381
Total	$18,232

Drilling Commitments
In December 2011, as part of our Utica joint venture development agreement with Total S.A. (Total) (see Note 8), we committed to spud no less than 90 cumulative Utica wells by December 31, 2012, 270 cumulative wells by December 31, 2013 and 540 cumulative wells by December 31, 2014. We met our 2012 commitment and, through March 31, 2013, we had spud 217 cumulative Utica wells and are on target to meet our 2013 commitment. If we fail to meet the drilling commitment at any such year end for any reason other than a force majeure event, the drilling carry percentage used to determine our promoted well reimbursement will be reduced from 60% to 45% for a number of wells drilled in the following calendar year equal to the number of wells we were short the drilling commitment. As such, any reduction would only affect the timing of the receipt of the drilling carry but not the total drilling carry to be received.
We have also committed to drill wells in conjunction with our CHK Utica and CHK C-T financial transactions and in conjunction with the formation of the Chesapeake Granite Wash Trust. See Note 6 for discussion of these transactions and commitments.
Property and Equipment Purchase Commitments
Much of the oilfield services equipment we purchase requires long production lead times. As a result, we have outstanding orders and commitments for such equipment. As of March 31, 2013, we had $85 million of purchase obligations related to future capital expenditures for drilling rigs and related equipment and hydraulic fracturing

equipment in 2013.

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Natural Gas and Liquids Purchase Commitments
We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners associated with our volumetric production payment (VPP) transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices. See Note 8 for further discussion of our VPP transactions.
Net Acreage Maintenance Commitments
Under the terms of our joint venture agreements with Statoil and Total (see Note 8), 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. To date, we have satisfied our replacement obligations under the Statoil agreement. We did not fully meet the initial net acreage maintenance commitment with Total under the terms of our Barnett Shale joint venture agreement as of the December 31, 2012 measurement date. As of December 31, 2012, we estimated a net acreage shortfall of approximately 13,000 net acres and anticipate making a cash payment of approximately $26 million to Total in the 2013 second quarter. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ from management’s estimates.
Affiliate Commitments
Under the terms of our corporate revolving bank credit facility, certain of our subsidiaries, including our oilfield services companies, are not guarantors of the credit facility debt. Transactions under certain agreements between us and our non-guarantor subsidiaries could affect our EBITDA or indebtedness for purposes of our credit facility covenant calculations, but they would have no effect on the consolidated financial statements because the transactions would be eliminated through consolidation. See Note 3 for discussion of our covenant calculations.
In October 2011, we entered into a services agreement with our wholly owned subsidiary, COO, under which we guarantee the utilization of a portion of COO’s drilling rig and hydraulic fracturing fleets during the term of the agreement. Through October 2016, we are subject to monetary penalties if we do not operate a specific number of COO’s drilling rigs or utilize a specific number of its hydraulic fracturing fleets. No payments have been made pursuant to the services agreement. Any payments made in future periods will be eliminated in consolidation.
Other Commitments
In April 2011, we entered into a master frac service agreement with our equity affiliate, FTS International, Inc. (FTS), which expires on December 31, 2014. Pursuant to this agreement, we are committed to enter into a predetermined number of backstop contracts, providing at least a 10% gross margin to FTS, if utilization of FTS fleets falls below a certain level. To date, we have not entered into any backstop contracts and, since we use hydraulic fracturing services continuously, we do not anticipate any material payments under this commitment.
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 two of which were issued in July 2011 and July 2012, with the remaining note scheduled to be issued in June 2013. 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 Longmont, Colorado. As of March 31, 2013, we had funded $115 million of our commitment. The remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached by July 2013. See Note 9 for further discussion of this investment.
In December 2011, we sold Appalachia Midstream Services, L.L.C., a wholly owned subsidiary of our wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), to Chesapeake Midstream Partners, L.P. (now named Access Midstream Partners, L.P. (NYSE:ACMP)) for total consideration of $884 million. In addition, CMD committed to pay ACMP for any quarterly shortfall between the actual adjusted EBITDA from the assets sold and specified quarterly targets, which total $100 million in 2012 and $150 million in 2013. We recorded this guarantee at an estimated fair value of $27 million at the time of the sale. No payment was required for the Current Quarter or for

2012, and we recognized $1 million of gain in the Current Quarter associated with the release of the liability related to the quarterly target achieved. The remaining $18 million fair value is included in other current liabilities on our condensed consolidated balance sheet as of March 31, 2013. We will release this liability over the remainder of 2013. To the extent

CMD is required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings.

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging, financial or performance assurances to third parties on behalf of our wholly owned guarantor subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantee our subsidiaries' future performance.

In connection with divestitures, our purchase and sale agreements generally provide indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party or in regards to perfecting title to property. These indemnifications generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or cannot be quantified at the time of the consummation of a particular transaction.

Certain of our natural gas and oil properties are burdened by non-operating interests such as royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which such interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests. See Note 8 for further discussion of our VPP transactions.

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5. Other Liabilities

Other current liabilities as of March 31, 2013 and December 31, 2012 are detailed below.

	March 31, 2013	December 31, 2012
	($ in millions)	
Revenues and royalties due others	$1,275	$1,337
Accrued natural gas, oil and NGL drilling and production costs	444	525
Joint interest prepayments received	594	749
Accrued payroll and benefits	128	224
Accrued dividends[(a)]	—	101
Other	847	805
Total other current liabilities	$3,288	$3,741

(a) On April 8, 2013, our Board of Directors declared dividends on our common and preferred shares outstanding. See Note 18 for further discussion.

Other long-term liabilities as of March 31, 2013 and December 31, 2012 are detailed below.

	March 31, 2013	December 31, 2012
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$269	$275
CHK C-T ORRI conveyance obligation[(b)]	160	164
Financing lease obligations[(c)]	143	143
Mortgages payable[(d)]	—	56
Other	560	538
Total other long-term liabilities	$1,132	$1,176

(a) $20 million and $18 million of the total $289 million and $293 million obligations are recorded in other current liabilities as of March 31, 2013 and December 31, 2012, respectively. See Note 6 for further discussion of the transaction.

(b) $13 million and $14 million of the total $173 million and $178 million obligation is recorded in other current liabilities as of March 31, 2013 and December 31, 2012, respectively. See Note 6 for further discussion of the transaction.

(c) In 2009, we financed 111 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 one of the assets in 2011.

(d) 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 had a floating interest rate of prime plus 275 basis points. In the Current Quarter, we prepaid the term loan in full without penalty. As of March 31, 2013, our Barnett Shale headquarters building was classified as property and equipment held for sale on our condensed consolidated balance sheet.

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6. Stockholders' Equity, Stock-Based Compensation, Performance Share Units and Noncontrolling Interests

Common Stock

The following is a summary of the changes in our common shares issued for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
	2013	2012
	(in thousands)	
Shares issued as of January 1	666,468	660,888
Restricted stock issuances (net of forfeitures)	2,631	3,184
Stock option exercises	176	109
Shares issued as of March 31	669,275	664,181

Preferred Stock

The following reflects our preferred shares outstanding for the three months ended March 31, 2013 and 2012:

	5.75%	5.75% (A)	4.5%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2013 and March 31, 2013	1,497	1,100	2,559	2,096
Shares outstanding as of January 1, 2012 and March 31, 2012	1,497	1,100	2,559	2,096

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.

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Stock-Based Compensation

Chesapeake's stock-based compensation program consists of restricted stock and stock options issued to employees and restricted stock issued to 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. For employees, this value is amortized over the vesting period, which is generally four years from the date of grant. For directors, although the restricted stock grants vest over three years, this value is expensed immediately as there is a non-substantive service condition for vesting. To the extent compensation cost relates to employees directly involved in the acquisition of natural gas and oil leasehold and 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, natural gas, oil and NGL production expenses, marketing, gathering and compression expenses or oilfield services expenses. We recorded the following stock-based compensation during the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Natural gas and oil properties	$21	$20
General and administrative expenses	20	19
Natural gas, oil and NGL production expenses	6	6
Marketing, gathering and compression expenses	3	4
Oilfield services expenses	3	3
Total	$53	$52

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. A summary of the unvested shares of restricted stock and changes during the three months ended March 31, 2013 is presented below.

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
	(in thousands)	
Unvested shares as of January 1, 2013	18,899	$23.72
Granted	4,945	$17.87
Vested	(4,740)	$23.66
Forfeited	(583)	$21.89
Unvested shares as of March 31, 2013	18,521	$22.23

The aggregate intrinsic value of restricted stock that vested during the Current Quarter was approximately $85 million based on the stock price at the time of vesting.

As of March 31, 2013, there was $275 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 2.6 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 and the Prior Quarter, we recognized reductions in tax benefits related to restricted stock of $10 million, and $4 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

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Stock Options
In the Current Quarter, we granted incentive-based and retention-based stock options to members of our senior management team. The incentive-based stock options will vest ratably over a three-year period and the retention-based stock options will vest one-third on each of the third, fourth and fifth anniversaries of the grant date. The stock option awards have an exercise price equal to the closing price of the Company's common stock on the grant date. Historically, we had granted stock options prior to 2006 under several stock compensation plans and they vested over a four-year period. Outstanding options expire ten years from the date of grant.
The following table provides information related to stock option activity for the three months ended March 31, 2013:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)			($ in millions)
Outstanding at January 1, 2013	481	$12.69	0.96	$2
Granted	4,563	$18.97		
Exercised	(178)	$11.06		
Outstanding at March 31, 2013	4,866	$18.64	9.27	$9
Exercisable at March 31, 2013	302	$13.66	0.74	$2

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

As of March 31, 2013, there was $27 million of total unrecognized compensation cost related to stock options. The cost is expected to be recognized over a weighted average period of approximately 3.4 years.
During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to stock options of $0 and a nominal amount, respectively. All amounts were recorded as adjustments to additional paid-in capital and deferred income taxes.

Performance Share Units
In January 2012 and 2013, we granted performance share units (PSUs) to senior management under our Long Term Incentive Plan that include both an internal performance measure and an external market condition. The 2012 awards vest over one-, two- and three-year service periods, and the 2013 awards vest over a three-year service period. The internal performance measure is considered a performance condition with a fair value generally equal to the Company's stock price. The external market condition is considered a market condition and generally requires Monte Carlo simulation to determine the fair value. The latter calculation for the 2012 awards is based on the absolute total shareholder return (TSR) of Chesapeake common stock and the relative TSR of Chesapeake common stock compared to the TSR of certain peers. The calculation for the 2013 awards is based on the relative TSR of Chesapeake common stock compared to the TSR of certain peers.
For PSUs granted in 2012, each of the TSR and operational payout components can range from 0% to 125%. For PSUs granted in 2013, the TSR component can range from 0% and 125% and each of the two operational components can range from 0% to 62.5%, in each case resulting in a total range of payout from 0% to 200%. The PSUs can only be settled in cash, so they are classified as a liability in our condensed consolidated financial statements and are measured at fair value as of the grant date, with such value re-measured at the end of each reporting period. Compensation expense is recognized over the vesting period with a corresponding adjustment to the liability.

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As of the respective grant dates, the fair value of the 1,271,240 PSUs issued in 2012 was $35 million and the fair value of the 1,426,235 PSUs issued in 2013 was $30 million. As of March 31, 2013, the fair value of the PSUs was $57 million. We have recorded $5 million of this value as a short-term liability for PSUs that will be settled in January 2014 and $36 million as a long-term liability representing the portion of the award that will be settled in January 2015 or thereafter. The remaining $16 million relates to PSUs for which the requisite service period has not been completed.

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our natural gas and oil assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and the existing wells within an area of mutual interest in the Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 new net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK C-T limited liability company agreement (the CHK C-T LLC Agreement), as the holder of all the common shares and the sole managing member of CHK C-T, we maintain voting and managerial control of CHK C-T and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $225 million to the ORRI obligation and $1.025 billion to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheets. Pursuant to the CHK C-T LLC Agreement, CHK C-T is currently required to retain an amount of cash (measured quarterly) equal to (i) the next two quarters of preferred dividend payments plus (ii) its projected operating funding shortfall for the next six months (projected operating funding shortfall requirement ends on December 31, 2013). The amount so retained, approximately $37 million as of March 31, 2013, is reflected as restricted cash on our condensed consolidated balance sheet.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T, as determined in accordance with the CHK C-T LLC Agreement. Any such optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares unless we have not met our drilling commitment at such time, in which case an optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK C-T LLC Agreement, cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares may be redeemed at a valuation equal to the greater of a 9% internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid through redemption at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return to the investors. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of March 31, 2013, the redemption price and the liquidation preference were each $1,290 per preferred share.

We have committed to drill, for the benefit of CHK C-T in the area of mutual interest, a minimum of 37.5 net wells per six-month period through 2013, inclusive of wells drilled in 2012, and 25 net wells per six-month period in 2014 through 2016, up to a minimum cumulative total of 300 net wells. If we fail to meet the then-current cumulative drilling commitment in any six-month period, any optional cash distributions would be distributed 100% to the investors. If we fail to meet the then-current cumulative drilling commitment in two consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would increase by 3% per annum. In addition, if we fail to meet the then-current cumulative drilling commitment in four consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would be increased by an additional 3% per annum. Any such increase in the internal rate of return would be effective only until the end of the first succeeding six-month period in which we have met our then-current cumulative drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. Under the development agreement, approximately 20 and 23 qualified net wells were added in the Current Quarter and the Prior Quarter, respectively. Through March 31, 2013, we were on target to meet our 2013 drilling commitment associated with the CHK C-T transaction.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in up to 1,000 new net wells and the contributed wells on our Cleveland and Tonkawa leasehold is subject to an increase to 5% on net wells drilled in any year following a year in which we do not meet our commitment to drill the wells subject to the ORRI obligation, which runs from 2012 through the first quarter of 2025. However, in no event would we deliver to investors more than a total ORRI of 3.75% in existing wells and 1,000 new net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 160-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs once we have drilled a minimum of 867 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. Under the ORRI obligation, we delivered an ORRI in approximately 22 net wells in the Current Quarter and 17 net wells in the Prior Quarter. While operations began on April 1, 2012, all wells completed since January 1, 2012 are credited to the ORRI obligation of 1,000 new net wells. Through March 31, 2013, we have met all current commitments associated with the CHK C-T transaction.

As of March 31, 2013 and December 31, 2012, $1.015 billion was recorded as noncontrolling interests on our condensed consolidated balance sheets. In the Current Quarter and the Prior Quarter, income of $19 million and $0 was attributable to the noncontrolling interests of CHK C-T. No income was attributable to the noncontrolling interests of CHK C-T in the Prior Quarter as the operational effective date was April 1, 2012.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. CHK Utica is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. In exchange for all of the common shares of CHK Utica, we contributed to CHK Utica approximately 700,000 net acres of leasehold and the existing wells within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK Utica limited liability company agreement (the CHK Utica LLC Agreement), as the holder of all the common shares and the sole managing member of CHK Utica, we maintain voting and managerial control of CHK Utica and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $300 million to the ORRI obligation and $950 million to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheets. Pursuant to the CHK Utica LLC Agreement, CHK Utica is required to retain a cash balance equal to the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $44 million, is reflected as restricted cash on our condensed consolidated balance sheet as of March 31, 2013. In addition, pursuant to the CHK Utica LLC Agreement, with respect to any sales proceeds as defined by the agreement, CHK Utica is required to separately account for, and dedicate all of such sales proceeds to either (i) capital expenditures made by CHK Utica in connection with its assets or (ii) the redemption of CHK Utica preferred shares. As a result of the sale of noncore Utica Shale assets in the Current Quarter and 2012, the amount reserved for paying capital expenditures, approximately $130 million, is reflected as restricted cash in other long-term assets on our condensed consolidated balance sheet as of March 31, 2013.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. If we fail to meet the then-current drilling commitment in any year, we must pay CHK Utica $5 million for each well we are short of such drilling commitment. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica, as determined in accordance with the CHK Utica LLC Agreement. Any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares unless we have not met our drilling commitment during a liquidated damages period, in which case an optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK Utica LLC Agreement, cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part. The preferred shares may be redeemed at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation will increase to provide the investors the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of March 31, 2013, the redemption price and the liquidation preference were each approximately $1,305 per preferred share.

We have committed to drill, for the benefit of CHK Utica in the area of mutual interest, a minimum of 50 net wells per year from 2012 through 2016, up to a minimum cumulative total of 250 net wells. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. See Note 8 for further discussion of the joint venture. Under the development agreement, approximately 27 and 12 qualified net wells were added in the Current Quarter and Prior Quarter, respectively. Through March 31, 2013, we were on target to meet our 2013 drilling commitment associated with the CHK Utica transaction.

The CHK Utica investors' right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on our Utica Shale leasehold is subject to an increase to 4% on net wells drilled in any year following a year in which we do not meet our commitment to drill the wells subject to the ORRI obligation, which runs from 2012 through 2023. However, in no event would we deliver to investors more than a total ORRI of 3% in 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs once we have drilled a minimum of 1,300 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. Under the ORRI obligation, we delivered an ORRI in approximately 11 new net wells in the Current Quarter. We did not meet our ORRI commitment in 2012. The ORRI increased to 4% for wells drilled or to be drilled in 2013, and the ultimate number of wells in which we must assign an interest will be reduced accordingly.

As of March 31, 2013 and December 31, 2012, $950 million was recorded as noncontrolling interests on our condensed consolidated balance sheets. For the Current Quarter and the Prior Quarter, income of approximately $22 million was attributable to the noncontrolling interests of CHK Utica. Subsequent to March 31, 2013, we purchased approximately 15% of the outstanding CHK Utica preferred shares from existing investors for $213 million. See Note 18 for further discussion of this transaction.

Chesapeake Granite Wash Trust. In November 2011, Chesapeake Granite Wash Trust (the Trust) sold 23,000,000 common units representing beneficial interests in the Trust at a price of $19.00 per common unit in its initial public offering. The common units are listed on the New York Stock Exchange and trade under the symbol "CHKR". We own 12,062,500 common units and 11,687,500 subordinated units, which in the aggregate represent an approximate 51% beneficial interest in the Trust. The Trust has a total of 46,750,000 units outstanding.

In connection with the initial public offering of the Trust, we conveyed royalty interests to the Trust that entitle the Trust to receive (i) 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 producing wells, and (ii) 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,000 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill, or cause to be drilled, the development wells at our own expense prior to June 30, 2016, and the Trust will not be responsible for any costs related to the drilling of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining interests in the undeveloped properties that are subject to the development agreement in order to secure our drilling obligation to the Trust, although the maximum amount that may be recovered by the Trust under such lien could not exceed $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of March 31, 2013, we had drilled

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or caused to be drilled approximately 64 development wells, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $120 million.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for such quarter. If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to us to satisfy our drilling obligation and perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on the Trust units in any quarter exceeds the applicable incentive threshold for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following our satisfaction of our drilling obligation with respect to the development wells, the subordinated units will automatically convert into common units on a one-for-one basis and our right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share in the Trust's distributions on a pro rata basis.

On February 8, 2013, the Trust declared a cash distribution of $0.6700 per common unit and $0.3772 per subordinated unit for the three-month period ended December 31, 2012 and covering production for the period from September 1, 2012 to November 30, 2012. The distribution paid to third-party unitholders on March 1, 2013 was approximately $15 million.

On February 8, 2012, the Trust declared a cash distribution of $0.7277 per unit for the three-month period ended December 31, 2011 and covering production for the period from September 1, 2011 to November 30, 2011. The distribution paid to third-party unitholders on March 1, 2012 was approximately $17 million.

We have determined that the Trust constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our condensed consolidated financial statements. As of March 31, 2013 and December 31, 2012, $344 million and $356 million, respectively, were recorded as noncontrolling interests on our condensed consolidated balance sheets. For the Current Quarter and the Prior Quarter, approximately $5 million and $3 million of income was attributable to the Trust's noncontrolling interests in our condensed consolidated statements of operations. See Note 10 for further discussion of VIEs.

Wireless Seismic, Inc. We have a controlling 57% equity interest in Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and eventual production of wireless seismic systems and any related technology that deliver seismic information obtained from standard geophones in real time to laptop and desktop computers. As a result of our control, Wireless is included in our condensed consolidated financial statements as of the 2012 fourth quarter. As of March 31, 2013 and December 31, 2012, $3 million and $5 million, respectively, was recorded as noncontrolling interests on our condensed consolidated balance sheets. In the Current Quarter, $1 million of Wireless' loss was attributable to noncontrolling interests of Wireless in our condensed consolidated statement of operations.

Big Star Crude Co., LLC. Oilfield Trucking Solutions, LLC, a wholly owned subsidiary of Chesapeake, entered into a joint venture to form Big Star Crude Co., LLC, which engages in commercial trucking. We have determined that Big Star is a VIE because our voting rights are disproportionate to our economic interests and the activities of the entity involve us and are conducted on our behalf. We have also determined that Chesapeake is the primary beneficiary, since it has the power to direct the activities of the VIE, has the obligation to absorb losses and has the right to receive benefits from the VIE. As a result, Big Star is included in our condensed consolidated financial statements as of the 2012 fourth quarter. As of March 31, 2013 and December 31, 2012, $1 million was recorded as noncontrolling interests on our condensed consolidated balance sheets. In the Current Quarter, a nominal amount of Big Star's loss was attributable to noncontrolling interests of Big Star in our condensed consolidated statement of operations.

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7. Derivative and Hedging Activities

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective prices to be received for our production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of March 31, 2013 and December 31, 2012, 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.
- Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- Swaptions: Chesapeake sells call swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our natural gas basis protection swaps 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. Our oil basis protection swaps 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.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty’s downside exposure below the second put option.

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 instrument assets (liabilities) as of March 31, 2013 and December 31, 2012 are provided below.

	March 31, 2013		December 31, 2012	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	586	$(233)	49	$24
Call options	193	(233)	193	(240)
Basis protection swaps	101	(15)	111	(15)
Three-way collars	72	(15)	—	—
Total natural gas	952	(496)	353	(231)
Oil (mmbbl):				
Fixed-price swaps	43.8	(17)	28.1	68
Call options	69.5	(514)	73.8	(748)
Call swaptions	5.3	(6)	5.3	(13)
Basis protection swaps	3.2	(2)	5.5	—

Total oil	121.8	(539)	112.7	(693)
Total estimated fair value		$(1,035)		$(924)

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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 and locked-in gains and losses of settled designated derivative contracts, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized in natural gas, oil and NGL sales. Changes in the fair value of derivatives not designated as cash flow hedges that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within natural gas, oil and NGL sales. As of March 31, 2013, we did not have any natural gas or oil derivatives that were designated as cash flow hedges. Therefore, changes in the fair value of these derivatives are reported in the condensed consolidated statement of operations. See further discussion below under Cash Flow Hedges.

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

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Natural gas, oil and NGL sales	$1,595	$1,221
Gains (losses) on natural gas, oil and NGL derivatives	(142)	(153)
Total natural gas, oil and NGL sales	$1,453	$1,068

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.25 billion under the terms of the facility. As of March 31, 2013, we had hedged under the facility 1.5 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and NGL price and basis derivatives 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 at semi-annual collateral dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures, term loan and sale/leaseback agreements. 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 derivatives. In addition, there are volume-based sub-limits for natural gas, oil and NGL derivative instruments. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain requirements are met including maintaining specified collateral coverage ratios as well as maintaining credit ratings with either of the designated rating agencies at or above current levels. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into derivative instruments with the Company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

Interest Rate Derivatives

To mitigate a portion of our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of March 31, 2013 and December 31, 2012, 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.

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

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The notional amount and the estimated fair value of our interest rate derivative liabilities as of March 31, 2013 and December 31, 2012 are provided below.

	March 31, 2013		December 31, 2012	
	Notional Amount	Fair Value	Notional Amount	Fair Value
		($ in millions)		
Interest rate:				
Swaps	$1,750	$(37)	$1,050	$(35)
Swaptions	125	(2)	—	—
Totals	$1,875	$(39)	$1,050	$(35)

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

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Interest expense on senior notes	$186	$174
Interest expense on credit facilities	12	21
Interest expense on term loans	29	—
(Gains) losses on interest rate derivatives	4	4
Amortization of loan discount, issuance costs and other	19	1
Capitalized interest	(229)	(188)
Total interest expense	$21	$12

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 eight years, we will recognize $18 million in net 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. 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 are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $36 million as of March 31, 2013. The euro-denominated debt in long-term debt has been adjusted to $440 million as of March 31, 2013 using an exchange rate of $1.2816 to €1.00.

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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 hedged transaction occurs. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.
The following table presents the fair value and location of each classification of derivative instrument disclosed in the condensed consolidated balance sheets as of March 31, 2013 and December 31, 2012 on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value March 31, 2013 ($ in millions)	December 31, 2012
Asset Derivatives:			
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$18	$110
Commodity contracts	Long-term derivative instruments	22	5
Total		40	115
Liability Derivatives:			
Designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	(36)	(20)
Total		(36)	(20)
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(435)	(157)
Commodity contracts	Long-term derivative instruments	(640)	(882)
Interest rate contracts	Short-term derivative instruments	(2)	—
Interest rate contracts	Long-term derivative instruments	(37)	(35)
Total		(1,114)	(1,074)
Total derivative instruments		$(1,110)	$(979)

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All of the Company's derivative positions are subject to netting arrangements which provide for offsetting of asset and liability positions, as well as related cash collateral if applicable. Such netting arrangements generally do not have restrictions. Under such netting arrangements, the Company offsets the fair value of derivative instruments with cash collateral received or paid for those contracts executed with the same counterparty, which reduces the Company's total assets and liabilities. As of March 31, 2013 and December 31, 2012, we did not have any cash collateral balances for these derivatives.

The following tables present the netting offsets of derivative assets and liabilities as of March 31, 2013 and December 31, 2012:

	March 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Short-Term	Long-Term	Short-Term	Long-Term
	($ in millions)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$18	$22	$(435)	$(640)
Gross amounts offset in the condensed consolidated statements of financial position	(13)	(20)	13	20
Net amounts of assets (liabilities) presented in the statements of financial position	5	2	(422)	(620)
Interest Rate Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	(2)	(37)
Gross amounts offset in the condensed consolidated statements of financial position	—	—	—	—
Net amounts of assets (liabilities) presented in the statements of financial position	—	—	(2)	(37)
Foreign Currency Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(36)
Gross amounts offset in the condensed consolidated statements of financial position	—	—	—	—
Net amounts of assets (liabilities) presented in the statements of financial position	—	—	—	(36)
Total derivatives as reported	$5	$2	$(424)	$(693)

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	December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Short-Term	Long-Term	Short-Term	Long-Term
	($ in millions)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$110	$5	$(157)	$(882)
Gross amounts offset in the consolidated statements of financial position	(52)	(3)	52	3
Net amounts of assets (liabilities) presented in the statements of financial position	58	2	(105)	(879)
Interest Rate Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(35)
Gross amounts offset in the consolidated statements of financial position	—	—	—	—
Net amounts of assets (liabilities) presented in the statements of financial position	—	—	—	(35)
Foreign Currency Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(20)
Gross amounts offset in the consolidated statements of financial position	—	—	—	—
Net amounts of assets (liabilities) presented in the statements of financial position	—	—	—	(20)
Total derivatives as reported	$58	$2	$(105)	$(934)

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

Fair Value Hedges

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. We have elected not to designate any of our qualifying interest rate derivatives as fair value hedges. Therefore, changes in the fair value of all of our interest rate derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within interest expense.

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

		Three Months Ended March 31,	
Fair Value Derivatives	Location of Gain (Loss)	2013	2012
		($ in millions)	
Interest rate contracts	Interest expense	$2	$2

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Cash Flow Hedges

A reconciliation of the changes of accumulated other comprehensive income (loss) in the condensed consolidated statements of stockholders' equity related to our cash flow hedges is presented below.

	Three Months Ended March 31,			
	2013		2012	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(304)	$(189)	$(287)	$(178)
Net change in fair value	(2)	(1)	6	4
(Gains) losses reclassified to income	19	12	(3)	(2)
Balance, end of period	$(287)	$(178)	$(284)	$(176)

Approximately $166 million of the $178 million of accumulated other comprehensive loss as of March 31, 2013 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged items are still expected to occur. These amounts will be recognized in earnings in the month the originally forecasted hedged items occur. As of March 31, 2013, we expect to transfer approximately $19 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amount will be transferred by December 31, 2022. As of March 31, 2013, none of our open commodity derivative instruments were designated as a cash flow hedge.

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

Cash Flow Derivatives	Location of Gain (Loss)	Three Months Ended March 31, 2013	2012
		($ in millions)	
Gain (Loss) Recognized in AOCI (Effective Portion):			
Commodity contracts	AOCI	$—	$1
Foreign currency contracts	AOCI	(2)	5
		$(2)	$6
Gain (Loss) Reclassified from AOCI (Effective Portion):			
Commodity contracts	Natural gas, oil and NGL sales	$(19)	$3
		$(19)	$3

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Undesignated Derivatives

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

Derivative Contracts	Location of Gain (Loss)	Three Months Ended March 31, 2013	2012
		($ in millions)	
Commodity contracts	Natural gas, oil and NGL sales	$(123)	$(156)
Interest rate contracts	Interest expense	(6)	(6)
Equity contracts	Other income	—	(2)
Total		$(129)	$(164)

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment-grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of March 31, 2013, our natural gas, oil and interest rate derivative instruments were spread among 15 counterparties. Additionally, counterparties to our multi-counterparty secured hedging facility described previously are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our natural gas, oil and NGL derivatives.

8. Acquisitions and Divestitures of Natural Gas and Oil Properties

Divestitures of Natural Gas and Oil Properties

During the Current Quarter and the Prior Quarter, excluding proceeds received from selling additional interests in our joint venture leasehold described under Joint Ventures below, we received proceeds of approximately $165 million and $59 million, respectively, related to divestitures of noncore natural gas and oil properties.

Under full cost accounting rules, we accounted for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. In conjunction with certain of these transactions, affiliates of our former Chief Executive Officer, Aubrey K. McClendon, sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and the net proceeds were paid to the sellers based on their respective ownership. These interests were acquired through the FWPP, which provides Mr. McClendon a contractual right to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company’s leasehold through June 2014.

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Joint Ventures

As of March 31, 2013, we had entered into seven significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in seven different resource plays and received cash of $7.1 billion and commitments to pay future drilling and completion costs of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and, in certain transactions, marketing activities for the project. The carry obligations paid by a joint venture partner are for a specified percentage of our drilling and completion costs. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carry obligations at the same time we bill them and other joint working interest owners for their share of drilling costs as they are incurred. 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 Sold	Cash Proceeds Received at Closing	Total Drilling Carries		Total Cash and Drilling Carry Proceeds	Drilling Carries Remaining[b]
				($ in millions)				
Utica	TOT	December 2011	25.0%	$610	$1,422	[c]	$2,032	$1,007
Niobrara	CNOOC	February 2011	33.3%	570	697	[d]	1,267	428
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800	1,404		2,204	—
Marcellus	STO	November 2008	32.5%	1,250	2,125		3,375	—
Fayetteville	BP	September 2008	25.0%	1,100	800		1,900	—
Haynesville & Bossier	PXP	July 2008	20.0%	1,650	1,508		3,158	—
				$7,100	$9,036		$16,136	$1,435

(a) Joint venture partners include Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Plains Exploration & Production Company (PXP).
(b) As of March 31, 2013.
(c) The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize these drilling carry commitments prior to expiration. See Note 4 for further discussion of the Utica drilling carries.
(d) The Niobrara drilling carries cover 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize these drilling carry commitments prior to expiration.

During the Current Quarter and the Prior Quarter, our drilling and completion costs included the benefit of approximately $180 million and $448 million, respectively, in drilling and completion carries paid by our joint venture partners.

During the Current Quarter and the Prior Quarter, we sold interests in additional leasehold we acquired in the Marcellus, Barnett and Utica shale plays to our joint venture partners TOT and STO for approximately $25 million and $18 million, respectively.

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Volumetric Production Payments

From time to time, we have sold 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 all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. For all of our VPP transactions, we have novated hedges to each of the respective VPP buyers and such hedges covered all VPP volumes sold. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing wellbores.

As the operator of the properties from which the VPP volumes have been sold, we have the responsibility to bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining the cost center ceiling for impairment purposes and in determining our standardized measure. Pursuant to SEC guidelines, the estimates used for purposes of determining the cost center ceiling and the standardized measure are based on current costs. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

Our outstanding VPPs consist of the following:

VPP #	Date of VPP	Division	Proceeds	Volume Sold Natural Gas	Oil	NGL	Total
			($ in millions)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$744	87	3.0	9.2	160
9	May 2011	Mid-Continent	853	138	1.7	4.8	177
8	September 2010	Barnett Shale	1,150	390	—	—	390
6	February 2010	East Texas and Texas Gulf Coast	180	44	0.3	—	46
5	August 2009	South Texas	370	67	0.2	—	68
4	December 2008	Anadarko and Arkoma Basins	412	95	0.5	—	98
3	August 2008	Anadarko Basin	600	93	—	—	93

2	May 2008	Texas, Oklahoma and Kansas	622	94	—	—	94
1	December 2007	Kentucky and West Virginia	1,100	208	—	—	208
			$6,031	1,216	5.7	14.0	1,334

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The volumes produced on behalf of our VPP buyers for the Current Quarter and the Prior Quarter were as follows:

	Three Months Ended March 31, 2013			Three Months Ended March 31, 2012		
VPP #	Natural Gas (bcf)	Oil (mbbl)	NGL (mbbl)	Natural Gas (bcf)	Oil (mbbl)	NGL (mbbl)
10	4	154.0	407.7	2	97.0	217.8
9	4	56.2	148.5	5	66.6	169.3
8	18	—	—	22	—	—
7	—	—	—	—	175.0	—
6	1	6.0	—	1	6.0	—
5	2	6.0	—	2	7.6	—
4	3	14.6	—	3	16.7	—
3	2	—	—	3	—	—
2	3	—	—	3	—	—
1	4	—	—	4	—	—
	41	236.8	556.2	45	368.9	387.1

The volumes remaining to be delivered on behalf of our VPP buyers as of March 31, 2013 were as follows:

		Volume Remaining as of March 31, 2013			
VPP #	Term Remaining (in months)	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
10	107	65	2.1	7.1	119.6
9	95	98	1.2	3.3	125.0
8	29	146	—	—	145.8
6	82	25	0.2	—	26.0
5	46	22	0.1	—	22.9
4	45	32	0.2	—	33.4
3	76	37	—	—	37.0
2	73	28	—	—	28.2
1	117	116	—	—	116.1
		569	3.8	10.4	654.0

For accounting purposes, cash proceeds from the sale of VPPs were reflected as a reduction of natural gas and oil properties with no gain or loss recognized, and our proved reserves were reduced accordingly.
In September 2012, to facilitate the sales process associated with our Permian Basin divestiture packages, we purchased the remaining reserves from our Permian Basin VPP (VPP #7), originally sold in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets.

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9. Investments

As of March 31, 2013 and December 31, 2012, we had the following investments:

	Approximate Ownership %	Accounting Method	Carrying Value March 31, 2013	December 31, 2012
			($ in millions)	
FTS International, Inc.	30%	Equity	$286	$298
Chaparral Energy, Inc.	20%	Equity	142	141
Sundrop Fuels, Inc.	50%	Equity	103	111
Clean Energy Fuels Corp.	—	Cost	100	100
Twin Eagle Resource Management, LLC	30%	Equity	33	34
Maalt Specialized Bulk, LLC	49%	Equity	13	13
Clean Energy Fuels Corp.	1%	Fair Value	13	12
Gastar Exploration Ltd.	10%	—	9	8
Other	—	—	12	11
Total investments			$711	$728

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company which, through its subsidiaries, provides hydraulic fracturing and other services to oil and gas companies.

During the Current Quarter, we recorded negative equity method adjustments, prior to intercompany profit eliminations, of $26 million for our share of FTS's net loss and recorded accretion adjustments of $11 million related to the excess of our underlying equity in net assets of FTS over our carrying value. The carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $510 million as of March 31, 2013, of which $187 million was attributed to goodwill. During the Current Quarter, the value attributed to goodwill decreased by $107 million, which represents our proportionate share, net of tax, of an impairment recorded by FTS related to its goodwill. The value not attributed to goodwill is being accreted over the nine-year estimated useful lives of the underlying assets.

In the Current Quarter, we purchased our pro-rata share, equal to approximately $3 million, of FTS common stock offered to existing stockholders of FTS. In November 2012, we purchased our pro-rata share, equal to approximately $106 million, of preferred equity securities offered by FTS to existing stockholders. Each share of preferred stock is convertible into a specified number of shares of FTS common stock automatically upon a qualified initial public offering of FTS common stock and at our option at any time following the second anniversary of the issue date.

Chaparral Energy, Inc. Chaparral Energy, Inc., based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties.

In the Current Quarter, we recorded a positive equity method adjustment of $4 million related to our share of Chaparral's net income, a $2 million charge related to our share of its other comprehensive income, and an amortization adjustment of $1 million related to our carrying value in excess of our underlying equity in net assets. The carrying value of our investment in Chaparral was in excess of our underlying equity in net assets by approximately $51 million as of March 31, 2013. 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.

Sundrop Fuels, Inc. 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 Longmont, Colorado. The investment is being used to 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. As of March 31, 2013, we had funded $115 million of our commitment. The remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are

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expected to be reached by July 2013. The full investment will represent approximately 50% of Sundrop Fuels' equity on a fully diluted basis.

In the Current Quarter, we recorded an $8 million charge related to our share of Sundrop's net loss. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $53 million as of March 31, 2013. This excess will be amortized over the life of the plant, once it is placed into service.

Clean Energy Fuels Corp. 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 two of which were issued in July 2011 and July 2012, with the remaining note scheduled to be issued in 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 is using 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.

In December 2011, we also purchased one million shares of Clean Energy common stock for $10 million and classified this investment as available-for-sale and reported it at fair value. In the Current Quarter, the carrying value of our investment increased by $1 million as the common stock price of Clean Energy changed from $12.45 per share as of December 31, 2012 to $13.00 per share as of March 31, 2013. Through March 31, 2013, we had recorded a mark-to-market pre-tax gain of $3 million in accumulated other comprehensive income for this investment.

Twin Eagle Resource Management LLC. In 2010, we invested $20 million in Twin Eagle Resource Management LLC, a natural gas trading and management firm. During the Current Quarter, we recorded a $1 million charge related to our share of Twin Eagle's net loss.

Maalt Specialized Bulk, LLC. In 2011, PTL Prop Solutions, LLC, a wholly owned subsidiary of Chesapeake, invested $12 million in Maalt Specialized Bulk, LLC (Maalt), which engages in bulk transportation services of sand.

Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE MKT: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. Our investment in Gastar has a cost basis of $89 million and is classified as available-for-sale. During the Current Quarter, the carrying value of our investment increased due to a settlement agreement between Gastar and Chesapeake, with Gastar purchasing the shares held by Chesapeake for $1.44 per share, an increase from the market price of $1.21 per share as of December 31, 2012. In March 2009, we booked an other-than-temporary-impairment of $70 million, and, through March 31, 2013, we had recorded a mark-to-market pre-tax loss of $10 million in accumulated other comprehensive income for this investment which was realized in impairment of investments in the Current Quarter. Pursuant to the settlement agreement and purchase and sale agreement with Gastar, we will also receive $75 million in cash in exchange for certain natural gas- and oil-producing properties and leasehold for dismissal of a lawsuit against Gastar. We expect this transaction to close in the 2013 second quarter.

10. Variable Interest Entities

We consolidate the activities of VIEs of which we are the primary beneficiary. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform qualitative analysis of the entity's design, organizational structure, primary decision makers and relevant agreements.

Consolidated VIE

Chesapeake Granite Wash Trust. For a discussion of the formation, operations and presentation of the Trust, please see Noncontrolling Interests in Note 6. The Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust. Our ownership in the Trust and our obligations under the development agreement and related drilling support lien constitute variable interests. We have determined that we are the primary beneficiary of the Trust as (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our obligations

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to perform under the development agreement, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that could potentially be significant to the Trust. As a result, we consolidate the Trust in our financial statements, and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake's debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the undeveloped portion of an area of mutual interest, if we do not meet our drilling commitment. In consolidation, as of March 31, 2013, approximately $379 million of net natural gas and oil properties, $23 million of current liabilities, $1 million of cash and cash equivalents, $6 million of short-term derivative liabilities and $3 million of long-term derivative liabilities were attributable to the Trust. We have presented parenthetically on the face of the condensed consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Unconsolidated VIE

Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership is to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. We are committed to acquire for our own account (outside the partnership) 10% of any acquisition agreed upon by the partnership up to a maximum of $25 million, and the partnership will acquire the remaining 90% up to a maximum of $225 million, funded entirely by KKR, making KKR the sole equity investor. We have significant influence over the decisions made by the partnership, as we hold two of five seats on the board of directors. We will receive proportionate distributions from the partnership of any cash received from royalties in excess of expenses paid, ranging from 7% to 22.5%. The partnership is considered a VIE because KKR's control over the partnership is disproportionate to its economic interest. This VIE remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. We are using the equity method to account for this investment.

11. Net Gains on Sales of Fixed Assets

For assets outside of our full cost pool, the costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from accounts, and the resulting gain or loss is reflected in operating costs. A summary of our gains or losses by asset class for the Current Quarter and Prior Quarter is as follows:

	Three Months Ended March 31,	
	2013	2012
Gathering systems and treating plants[(a)]	$69	$1
Drilling rigs and equipment	(1)	—
Buildings and land[(b)]	(22)	—
Other	3	1
Total net gains on sales	$49	$2

(a) In the Current Quarter, we sold our interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP for proceeds of approximately $134 million. We recorded a $56 million pre-tax gain associated with this transaction.

(b) In the Current Quarter, the net losses on sales of buildings and land were primarily from the sale of certain of our buildings and land in our Barnett Shale operating area.

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12. Impairments of Fixed Assets and Other

We test our long-lived assets, other than natural gas and oil properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable and recognize an impairment loss if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. In the Current Quarter, we recognized $27 million of impairment losses on certain of our buildings and land classified as held for sale. We received a purchase offer from a third party that we used to determine the fair value of the assets. The buildings and land are included in our other operating segment.

13. Employee Retirement and Other Termination Benefits

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and Chief Executive Officer (CEO) and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon's departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells, leases and acreage. In the Current Quarter, we accrued for the termination benefits that will be afforded Mr. McClendon under the terms of his separation and services agreement.

In December 2012, Chesapeake announced that it had offered a voluntary separation program (VSP) to certain employees as part of the Company's ongoing efforts to improve efficiencies and reduce costs. The VSP was offered to approximately 275 employees who met criteria based upon a combination of age and years of Chesapeake service. Employees had until February 7, 2013 to respond, and 211 employees accepted the offer.

In addition, we provide benefits under certain circumstances to other employees that retire from or are terminated by Chesapeake. During the Current Quarter, we recorded the following expenses related to the termination benefits provided to Mr. McClendon, the VSP participants and others.

	Three Months Ended March 31, 2013 ($ in millions)
Termination benefits provided to Mr. McClendon:	
Salary and bonus expense	$11
Acceleration of 2008 performance bonus “claw-back” feature	11
Acceleration of stock-based compensation awards	22
Acceleration of performance share unit awards	13
Estimated aircraft usage benefits	7
Total termination benefits provided to Mr. McClendon	64
Termination benefits provided to VSP participants:	
Salary and bonus expense	30
Acceleration of restricted stock awards	24
Other associated costs	2
Total termination benefits provided to VSP participants	56
Other termination benefits	13
Total employee retirement and other termination benefits	$133

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14. 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.

Recurring Fair Value Measurement

Other Current Assets. Current assets related to forfeited 401(k) employee contributions are invested in traded securities.

Investments. The fair value of Chesapeake's investment in Clean Energy Fuels Corp. (NASDAQ:CLNE) common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. Assets and liabilities related to Chesapeake's deferred compensation plan are included in other long-term assets and other long-term liabilities, respectively. The fair values of these assets and liabilities are determined using quoted market prices, as the plan consists of exchange-traded mutual funds and Chesapeake common stock.

Derivatives. The fair value of most of our derivatives is 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 natural gas, oil, NGL, interest rate and cross currency swaps do not include optionality and therefore generally 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 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 either party to a contract will be unable to meet its obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

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The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of March 31, 2013:

	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):				
Other current assets	$7	$—	$—	$7
Investments	13	—	—	13
Other long-term assets	82	—	—	82
Other long-term liabilities	(87)	—	—	(87)
Derivatives:				
Commodity assets	—	32	8	40
Commodity liabilities	—	(282)	(793)	(1,075)
Interest rate liabilities	—	(37)	(2)	(39)
Foreign currency liabilities	—	(36)	—	(36)
Total derivatives	—	(323)	(787)	(1,110)
Total	$15	$(323)	$(787)	$(1,095)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2012:

	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):				
Other current assets	$4	$—	$—	$4
Investments	20	—	—	20
Other long-term assets	88	—	—	88
Other long-term liabilities	(87)	—	—	(87)
Derivatives:				
Commodity assets	—	105	10	115
Commodity liabilities	—	(13)	(1,026)	(1,039)
Interest rate liabilities	—	(35)	—	(35)
Foreign currency liabilities	—	(20)	—	(20)
Total derivatives	—	37	(1,016)	(979)
Total	$25	$37	$(1,016)	$(954)

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

	Derivatives Commodity	Interest Rate
	($ in millions)	
Beginning Balance as of January 1, 2013	$(1,016)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	194	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	(1)
Settlements	37	—
Ending Balance as of March 31, 2013	$(785)	$(2)
Beginning Balance as of January 1, 2012	$(1,654)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	(59)	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	(2)
Settlements	8	—
Ending Balance as of March 31, 2012	$(1,705)	$(3)

(a)

	Natural Gas, Oil and NGL Sales		Interest Expense	
	2013	2012	2013	2012
	($ in millions)			
Total gains (losses) included in earnings for the period	$194	$(59)	$(1)	$(1)
Change in unrealized gains (losses) relating to assets still held at reporting date	$191	$(132)	$(2)	$(3)

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Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas and oil, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts. For example, an increase (decrease) in the forward prices and volatility of natural gas and oil prices will decrease (increase) the fair value of natural gas and oil derivatives and adverse changes to our counterparties' creditworthiness will decrease the fair value of our derivatives.

Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value March 31, 2013 ($ in millions)
Oil Trades[a]	Oil price volatility curves	9.40% - 22.10%	17.17 %	$(520)
Oil Basis Swaps[b]	Physical pricing point forward curves	$9.41 - $15.43	$12.79	$(2)
Natural Gas Trades[a]	Natural gas price volatility curves	20.70% - 34.15%	25.52 %	$(248)
Natural Gas Basis Swaps[b]	Physical pricing point forward curves	($1.40) - $0.06	$(0.20)	$(15)

(a) Fair value is based on an estimate derived from option models.
(b) Fair value is based on an estimate of discounted cash flows.

Nonrecurring Fair Value Measurements

Fair value measurements were applied with respect to our non-financial assets, measured on a nonrecurring basis, to determine impairments. In the Current Quarter, these assets consisted primarily of land and buildings. We have either received a bid from a third party or used a third party to assess the fair value of these assets. Since the inputs used are not observable in the market, these assets are classified as Level 3 in the fair value hierarchy.

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. The carrying values of financial instruments comprising cash and cash equivalents, restricted cash, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, which consists of our credit facilities and our term loans, is estimated using our credit default swap rate (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	March 31, 2013		December 31, 2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		($ in millions)		
Current maturities of long-term debt (Level 1)	$—	$—	$463	$480
Long-term debt (Level 1)	$10,229	$10,193	$9,759	$10,457
Long-term debt (Level 2)	$3,203	$3,160	$2,378	$2,284

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

15. Segment Information

In accordance with accounting guidance for disclosures about segments of an enterprise and related information, we have three reportable operating segments. Our exploration and production operating segment, natural gas, oil and NGL marketing, gathering and compression operating segment and oilfield services 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, oil and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas, oil and NGL primarily from Chesapeake-operated wells. The oilfield services operating segment is responsible for contract drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas, oil and NGL related to Chesapeake's ownership interests by the marketing, gathering and compression operating segment are reflected as exploration and production revenues. Such amounts totaled $1.7 billion and $1.2 billion for the Current Quarter and the Prior Quarter, respectively. The following table presents selected financial information for Chesapeake's operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Three Months Ended March 31, 2013:						
Revenues	$1,453	$3,529	$538	$10	$(2,106)	$3,424
Intersegment revenues	—	(1,748)	(352)	(6)	2,106	—
Total revenues	$1,453	$1,781	$186	$4	$—	$3,424
Income (Loss) Before Income Taxes	$170	$129	$22	$(58)	$(98)	$165
Three Months Ended March 31, 2012:						
Revenues	$1,068	$2,392	$447	$—	$(1,488)	$2,419
Intersegment revenues	—	(1,176)	(312)	—	1,488	—
Total revenues	$1,068	$1,216	$135	$—	$—	$2,419
Income (Loss) Before Income Taxes	$86	$66	$40	$(100)	$(97)	$(5)
As of March 31, 2013:						
Total Assets	$37,756	$2,499	$2,190	$2,526	$(2,490)	$42,481
As of December 31, 2012:						
Total Assets	$37,004	$2,291	$2,115	$2,529	$(2,328)	$41,611

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16. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, 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 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our oilfield services subsidiary, COS, and its subsidiaries were released as guarantors in October 2011 when they were reorganized and separately capitalized and are not currently guarantors of our senior notes or our other debt obligations, but are subject to the covenants and guarantees in the oilfield services revolving bank credit facility agreement referred to in Note 3 that limit their ability to pay dividends or distributions or make loans to Chesapeake. Our midstream subsidiary, CMD, and certain of its subsidiaries, including Chesapeake Midstream Operating, L.L.C. (CMO), were added as guarantors of our senior notes and certain other obligations in June 2012 upon the termination of the midstream credit facility. In December 2012 upon the sale of CMO to ACMP, CMO and its subsidiaries were then released as guarantors of our senior notes and of our other debt obligations. All prior year information has been restated to reflect COS, CMO and their subsidiaries as non-guarantor subsidiaries and CMD and certain of its remaining subsidiaries as guarantor subsidiaries. Certain of our oilfield services subsidiaries and subsidiaries formed to invest in natural gas demand initiatives, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain de minimis subsidiaries are also non-guarantors.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of March 31, 2013 and December 31, 2012 and for the three months ended March 31, 2013 and 2012. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF MARCH 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$—	$—	$ 33	$—	$33
Restricted cash	—	—	81	—	81
Other	4	2,614	619	(478)	2,759
Current assets held for sale	—	11	—	—	11
Total Current Assets	4	2,625	733	(478)	2,884
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,782	3,074	36	32,892
Other property and equipment, net	—	2,692	1,975	—	4,667
Property and equipment held for sale, net	—	588	—	—	588
Total Property and Equipment, Net	—	33,062	5,049	36	38,147
LONG-TERM ASSETS:					
Other assets	207	1,378	237	(372)	1,450
Investments in subsidiaries and intercompany advances	2,863	176	—	(3,039)	—
TOTAL ASSETS	$3,074	$37,241	$ 6,019	$(3,853)	$42,481
CURRENT LIABILITIES:					
Current liabilities	$133	$5,560	$ 550	$(478)	$5,765
Current liabilities held for sale	—	20	—	—	20
Intercompany payable to (receivable from) parent	(24,957)	23,887	964	106	—
Total Current Liabilities	(24,824)	29,467	1,514	(372)	5,785
LONG-TERM LIABILITIES:					
Long-term debt, net	11,560	832	1,057	—	13,449
Deferred income tax liabilities	382	2,581	128	(70)	3,021
Other long-term liabilities	256	1,498	830	(372)	2,212
Total Long-Term Liabilities	12,198	4,911	2,015	(442)	18,682
EQUITY:					
Chesapeake stockholders' equity	15,700	2,863	2,490	(5,353)	15,700
Noncontrolling interests	—	—	—	2,314	2,314
Total Equity	15,700	2,863	2,490	(3,039)	18,014
TOTAL LIABILITIES AND EQUITY	$3,074	$37,241	$ 6,019	$(3,853)	$42,481

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$—	$228	$ 59	$—	$287
Restricted cash	—	—	111	—	111
Other	1	2,369	513	(337)	2,546
Current assets held for sale	—	—	4	—	4
Total Current Assets	1	2,597	687	(337)	2,948
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost, based on full cost accounting, net	—	29,063	3,077	(222)	31,918
Other property and equipment, net	—	3,066	1,549	—	4,615
Property and equipment held for sale, net	—	255	379	—	634
Total Property and Equipment, Net	—	32,384	5,005	(222)	37,167
LONG-TERM ASSETS:					
Other assets	217	1,396	261	(378)	1,496
Investments in subsidiaries and intercompany advances	2,254	(185)	—	(2,069)	—
TOTAL ASSETS	$2,472	$36,192	$ 5,953	$(3,006)	$41,611
CURRENT LIABILITIES:					
Current liabilities	$789	$5,368	$ 426	$(338)	$6,245
Current liabilities held for sale	—	—	21	—	21
Intercompany payable to (receivable from) parent	(25,571)	24,372	1,330	(131)	—
Total Current Liabilities	(24,782)	29,740	1,777	(469)	6,266
LONG-TERM LIABILITIES:					
Long-term debt, net	11,089	—	1,068	—	12,157
Deferred income tax liabilities	361	2,415	127	(96)	2,807
Other liabilities	235	1,783	839	(372)	2,485
Total Long-Term Liabilities	11,685	4,198	2,034	(468)	17,449
EQUITY:					
Chesapeake stockholders' equity	15,569	2,254	2,142	(4,396)	15,569
Noncontrolling interests	—	—	—	2,327	2,327
Total Equity	15,569	2,254	2,142	(2,069)	17,896
TOTAL LIABILITIES AND EQUITY	$2,472	$36,192	$ 5,953	$(3,006)	$41,611

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES					
Natural gas, oil and NGL	$—	$1,322	$128	$3	$1,453
Marketing, gathering and compression	—	1,778	3	—	1,781
Oilfield services	—	—	554	(364)	190
Total Revenues	—	3,100	685	(361)	3,424
OPERATING EXPENSES					
Natural gas, oil and NGL production	—	296	11	—	307
Production taxes	—	51	2	—	53
Marketing, gathering and compression	—	1,742	3	—	1,745
Oilfield services	—	—	426	(271)	155
General and administrative	—	87	23	—	110
Natural gas, oil and NGL depreciation, depletion and amortization	—	591	57	—	648
Depreciation and amortization of other assets	—	48	71	(41)	78
Net gains on sales of fixed assets	—	(49)	—	—	(49)
Impairment of natural gas and oil properties	—	—	91	(91)	—
Impairments of fixed assets and other	—	27	—	—	27
Employee retirement and other termination benefits	—	131	2	—	133
Total Operating Expenses	—	2,924	686	(403)	3,207
INCOME (LOSS) FROM OPERATIONS	—	176	(1)	42	217
OTHER INCOME (EXPENSE)					
Interest expense	(219)	(3)	(21)	222	(21)
Losses on investments	—	(27)	—	—	(27)
Impairment of investment	—	(10)	—	—	(10)
Other income (expense)	216	14	3	(227)	6
Equity in net earnings of subsidiary	60	(87)	—	27	—
Total Other Income (Expense)	57	(113)	(18)	22	(52)
INCOME (LOSS) BEFORE INCOME TAXES	57	63	(19)	64	165
INCOME TAX EXPENSE (BENEFIT)	(1)	57	(7)	14	63
NET INCOME (LOSS)	58	6	(12)	50	102
Net income attributable to noncontrolling interests	—	—	—	(44)	(44)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	58	6	(12)	6	58
Other comprehensive income (loss)	(2)	14	—	—	12
	$56	$20	$(12)	$6	$70

COMPREHENSIVE INCOME (LOSS)
ATTRIBUTABLE TO CHESAPEAKE

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$1,044	$24	$—	$1,068
Marketing, gathering and compression	—	1,173	43	—	1,216
Oilfield services	—	—	449	(314)	135
Total Revenues	—	2,217	516	(314)	2,419
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	348	1	—	349
Production taxes	—	46	1	—	47
Marketing, gathering and compression	—	1,170	27	—	1,197
Oilfield services	—	—	355	(259)	96
General and administrative	—	109	26	1	136
Natural gas, oil and NGL depreciation, depletion and amortization	—	492	14	—	506
Depreciation and amortization of other assets	—	46	72	(34)	84
Net gains on sales of fixed assets	—	(1)	(1)	—	(2)
Total Operating Expenses	—	2,210	495	(292)	2,413
INCOME (LOSS) FROM OPERATIONS	—	7	21	(22)	6
OTHER INCOME (EXPENSE):					
Interest expense	(161)	(2)	(18)	169	(12)
Earnings (losses) on investments	—	(31)	26	—	(5)
Other income	163	9	34	(200)	6
Equity in net earnings of subsidiary	(29)	(18)	—	47	—
Total Other Income (Expense)	(27)	(42)	42	16	(11)
INCOME (LOSS) BEFORE INCOME TAXES	(27)	(35)	63	(6)	(5)
INCOME TAX EXPENSE (BENEFIT)	1	(7)	25	(21)	(2)
NET INCOME (LOSS)	(28)	(28)	38	15	(3)
Net income attributable to noncontrolling interests	—	—	—	(25)	(25)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(28)	(28)	38	(10)	(28)
Other comprehensive income (loss)	3	4	—	—	7
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(25)	$(24)	$38	$(10)	$(21)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
THREE MONTHS ENDED MARCH 31, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$790	$146	$(12)	$924
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(1,643)	(216)	—	(1,859)
Proceeds from divestitures of proved and unproved properties	—	138	52	—	190
Additions to other property and equipment	—	(186)	(144)	—	(330)
Other investing activities	—	135	74	45	254
Cash used in investing activities	—	(1,556)	(234)	45	(1,745)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	3,395	237	—	3,632
Payments on credit facilities borrowings	—	(2,563)	(248)	—	(2,811)
Proceeds from issuance of senior notes, net of discount and offering costs	—	—	—	—	—
Proceeds from sales of noncontrolling interests	—	—	—	—	—
Other financing activities	(133)	(94)	6	(33)	(254)
Intercompany advances, net	133	(200)	67	—	—
Cash provided by financing activities	—	538	62	(33)	567
Net increase (decrease) in cash and cash equivalents	—	(228)	(26)	—	(254)
Cash and cash equivalents, beginning of period	—	228	59	—	287
Cash and cash equivalents, end of period	$—	$—	$33	$—	$33

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
THREE MONTHS ENDED MARCH 31, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$346	$48	$(120)	$274
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(3,520)	(189)	—	(3,709)
Proceeds from divestitures of proved and unproved properties	—	821	—	—	821
Additions to other property and equipment	—	(229)	(461)	—	(690)
Other investing activities	—	720	(36)	(756)	(72)
Cash used in investing activities	—	(2,208)	(686)	(756)	(3,650)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	4,698	990	—	5,688
Payments on credit facilities borrowings	—	(3,956)	(590)	—	(4,546)
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	—	—	—	1,263
Proceeds from sales of noncontrolling interests	—	—	1,044	—	1,044
Other financing activities	(131)	(24)	(707)	876	14
Intercompany advances, net	(1,132)	1,144	(12)	—	—
Cash provided by financing activities	—	1,862	725	876	3,463
Net increase in cash and cash equivalents	—	—	87	—	87
Cash and cash equivalents, beginning of period	—	1	350	—	351
Cash and cash equivalents, end of period	$—	$1	$437	$—	$438

17. Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards:

Recently Adopted Accounting and Disclosure Changes

In February 2012, the FASB issued guidance changing the presentation and disclosure of significant reclassifications out of accumulated other comprehensive income when required to be reclassified to net income entirely. This standard became effective for us on January 1, 2013 and did not have a significant impact on our financial statement presentation, financial position, results of operations or liquidity.

In December 2011 and January 2013, the FASB issued guidance amending and expanding disclosure requirements about the nature of an entity's rights of offset and related arrangements associated with its derivatives. Both standards became effective for us on January 1, 2013. This guidance did not have a significant impact on our financial statement presentation, financial position, results of operations or liquidity.

Recently Issued Accounting and Disclosure Change

In February 2013, the FASB issued guidance on the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. This standard will become effective for us on January 1, 2014 and we do not expect it to have a significant impact on our financial statement presentation, financial position, results of operations or liquidity.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

18. Subsequent Events

On April 1, 2013, we issued $2.3 billion in aggregate principal amount of senior notes at par. The offering included three series of notes: $500 million in aggregate principal amount of 3.25% Senior Notes due 2016; $700 million in aggregate principal amount of 5.375% Senior Notes due 2021; and $1.1 billion in aggregate principal amount of 5.75% Senior Notes due 2023. We used the net proceeds of $2.277 billion to purchase outstanding senior notes through tender offers we commenced concurrently with the senior notes offering. We purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to those tender offers, which expired April 12, 2013. We will record a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million in deferred charges. We plan to use a substantial portion of the remaining net proceeds from the offering to redeem $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 (the “2019 Notes”) at par pursuant to notice of special early redemption. As described in the following paragraph, the notice has been the subject of recent litigation. Any proceeds remaining will be used to repay and/or retire at maturity all outstanding 7.625% Senior Notes due 2013 and to purchase, repay and/or redeem over time other outstanding indebtedness, including indebtedness outstanding under our corporate revolving bank credit facility.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York against The Bank of New York Mellon Trust Company, N.A. (BNY Mellon), the indenture trustee for the 2019 Notes. The Company sought a declaration that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par on May 13, 2013 (plus interest accrued to that date) was timely and effective pursuant to the “Special Early Redemption” provision of the supplemental indenture governing the 2019 Notes. BNY Mellon asserted that the March 15, 2013 notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose and because of the specific phrasing in the notice that provides that it will not be effective unless the Court concluded it was timely. The Court conducted a trial on the matter in late April and on May 8, 2013, ruled in the Company's favor. Accordingly, the Company is proceeding with its redemption of the 2019 Notes at par, with payment to be made on May 13, 2013 pursuant to the terms of the notice. The Company intends to proceed with the redemption even if BNY Mellon appeals the Court's ruling, unless the Court's ruling is stayed.

On April 8, 2013, our Board of Directors declared a $0.0875 per share quarterly dividend that was paid on April 30, 2013 to common shareholders of record on April 15, 2013. We have approximately 667 million shares outstanding. In addition, our Board declared dividends on the following preferred stock issuances: a $1.125 per share cash dividend on our 4.50% Cumulative Convertible Preferred Stock, payable on June 17, 2013; a $1.25 per share cash dividend on our 5% (2005B) Cumulative Convertible Preferred Stock, payable on May 15, 2013; a $14.375 cash dividend on our 5.75% Cumulative Convertible Preferred Stock, payable on May 15, 2013; and a $14.375 per share cash dividend on our 5.75% (Series A) Cumulative Convertible Preferred Stock, payable on May 15, 2013.

On April 30, 2013, our wholly owned midstream subsidiary, CMD, entered into an agreement to sell its wholly owned subsidiary, Mid-America Midstream Gas Services, L.L.C. (MAMGS), to Semgas, L.P. (SemGroup), a wholly owned subsidiary of SemGroup Corporation, for consideration of approximately $300 million in cash, subject to post-closing adjustments. MAMGS owns certain gathering and processing assets located in the Mississippi Lime play, and the transaction with SemGroup will include a new long-term fee-based gathering and processing agreement covering acreage dedication areas in the Mississippi Lime play. The sale is expected to close in the 2013 second quarter, subject to certain regulatory approvals and closing conditions.

On May 8, 2013, CMD sold its wholly owned subsidiary, Granite Wash Midstream Gas Services, L.L.C. (GWMGS), to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE), for consideration of approximately $245 million in cash, subject to post-closing adjustments. GWMGS owns certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE includes long-term fee-based agreements for gas gathering, compression, treating and processing services.

On May 8, 2013, we purchased 190,000 preferred shares of CHK Utica from existing investors in a privately negotiated transaction for approximately $213 million, or approximately $1,115 per share plus accrued dividends, reducing the amount of outstanding preferred shares held by third-party investors by approximately 15%. See Note 6 for further discussion of our CHK Utica transaction.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
Financial Data
The following table sets forth certain information regarding our production volumes, natural gas, oil and natural gas liquids (NGL) sales, average sales prices received, other operating income and expenses for the periods indicated:

	Three Months Ended March 31,	
	2013	2012
Net Production:		
Natural gas (bcf)	273.1	270.8
Oil (mmbbl)	9.3	6.0
NGL (mmbbl)	4.9	4.3
Natural gas equivalent (bcfe)[(a)]	358.1	332.8
Natural Gas, Oil and NGL Sales ($ in millions):		
Natural gas sales	$573	$478
Natural gas derivatives – realized gains (losses)	8	158
Natural gas derivatives – unrealized gains (losses)	(278)	(147)
Total natural gas sales	303	489
Oil sales	884	591
Oil derivatives – realized gains (losses)	(4)	(34)
Oil derivatives – unrealized gains (losses)	132	(138)
Total oil sales	1,012	419
NGL sales	138	152
NGL derivatives – realized gains (losses)	—	(7)
NGL derivatives – unrealized gains (losses)	—	15
Total NGL sales	138	160
Total natural gas, oil and NGL sales	$1,453	$1,068
Average Sales Price (excluding gains (losses) on derivatives):		
Natural gas ($ per mcf)	$2.10	$1.77
Oil ($ per bbl)	$95.23	$98.36
NGL ($ per bbl)	$28.25	$35.16
Natural gas equivalent ($ per mcfe)	$4.45	$3.67
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$2.13	$2.35
Oil ($ per bbl)	$94.85	$92.63
NGL ($ per bbl)	$28.25	$33.60
Natural gas equivalent ($ per mcfe)	$4.46	$4.02
Other Operating Income[(b)] ($ in millions):		
Marketing, gathering and compression net margin	$36	$19
Oilfield services net margin	$35	$39
Other Operating Income[(b)] ($ per mcfe):		
Marketing, gathering and compression net margin	$0.10	$0.06
Oilfield services net margin	$0.10	$0.12

	Three Months Ended March 31, 2013	2012
Expenses ($ per mcfe):		
Natural gas, oil and NGL production	$0.86	$1.05
Production taxes	$0.15	$0.14
General and administrative expenses[c]	$0.31	$0.41
Natural gas, oil and NGL depreciation, depletion and amortization	$1.81	$1.52
Depreciation and amortization of other assets	$0.22	$0.25
Interest expense[d]	$0.04	$0.02
Interest Expense ($ in millions):		
Interest expense	$17	$8
Interest rate derivatives – realized (gains) losses	(2)	—
Interest rate derivatives – unrealized (gains) losses	6	4
Total interest expense	$21	$12

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

(b) Includes revenue and operating costs and excludes depreciation and amortization of other assets. See Depreciation and Amortization of Other Assets under Results of Operations for details of the depreciation and amortization of other assets associated with our marketing, gathering and compression and oilfield services operating segments.

(c) Includes stock-based compensation.

(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.

Overview

We are the second-largest producer of natural gas, a top 11 producer of liquids and the most active driller of wells in the U.S. We own interests in approximately 46,100 producing natural gas and oil wells that are currently producing approximately 4.0 bcfe per day, net to our interest. The Company has built a large resource base of onshore U.S. unconventional natural gas and liquids assets. Our core natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the Barnett Shale in the Fort Worth Basin of north-central Texas. In addition, we have built leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio, West Virginia and Pennsylvania; the Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. The Company's investments in these 10 plays represent our core assets, which are the nearly exclusive focus of our planned future drilling activity. We have also vertically integrated many of our operations and own substantial marketing, compression and oilfield services businesses.

Our Current Quarter production of 358 bcfe consisted of 273 bcf of natural gas (76% on a natural gas equivalent basis), 9.3 mmbbls of oil (16% on a natural gas equivalent basis) and 4.9 mmbbls of NGL (8% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 3.979 bcfe, an increase of 321 mmcfe, or 9%, over the 3.658 bcfe produced per day in the Prior Quarter.

In recognition of the value gap between liquids and natural gas prices, Chesapeake directed a significant portion of its technological and leasehold acquisition expertise during the past four years to identify, secure and commercialize new unconventional liquids-rich plays. The results of this planned transition to a more balanced portfolio between natural gas and liquids are reflected in our Current Quarter production and revenue. In the Current Quarter, our production of liquids averaged approximately 157,390 bbls per day, a 39% increase over the Prior Quarter average, and we expect to increase our liquids production through our drilling activities by approximately 27% in 2013 compared to 2012. During the Current Quarter, realized revenue (excluding unrealized gains or losses on derivatives) from liquids production accounted for 64% of total natural gas, oil and NGL revenues, compared to 53% in the Prior Quarter.

In 2013, Chesapeake is pursuing four strategic initiatives aimed at accelerating the value that can be realized from the resource base we have assembled over the years. We are concentrating on developing existing assets, heightening operational excellence, increasing capital efficiency and maintaining financial discipline. We are developing existing assets by focusing our drilling on the core of the core of our leasehold positions, continuing to improve our liquids production mix and optimizing our portfolio by selling noncore assets or assets that are not a part of our long-term plans. Our operational excellence efforts are evidenced in faster spud-to-spud cycle times, process improvements and careful attention to safety, regulatory compliance and environmental stewardship measures. Through pad drilling, leveraging first well investments and capitalizing on the advantages we have with an integrated oilfield services segment, we are attaining capital efficiencies that allow us to deliver attractive profit margins and financial returns through all phases of the commodity price cycle. Finally, our strategic plan calls for financial discipline in the form of improved returns on capital, increased capital allocation to drilling and completion activities, a reduction in funding gaps, a reduction in financial risk and complexity and an overall reduction in costs.

Recent Developments

Management and Board Changes

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and Chief Executive Officer (CEO) and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon's departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells, leases and acreage. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

On March 29, 2013, the Board of Directors named Steven C. Dixon Acting CEO of the Company in addition to his continuing service as Executive Vice President - Operations and Geosciences and Chief Operating Officer. Mr. Dixon's appointment as Acting CEO was effective April 1, 2013, following Mr. McClendon's separation from the Company. On March 29, 2013, the Board also established a three-person Office of the Chairman while continuing the CEO search process. The Office of the Chairman includes Archie W. Dunham, non-executive Chairman of the Board; Mr. Dixon; and Domenic J. Dell’Osso, Jr., Executive Vice President - Chief Financial Officer.

On March 7, 2013, we announced that the Board of Directors accepted the resignation of board member V. Burns Hargis and that Louis A. Raspino had been appointed to fill the vacancy and appointed chairman of the audit committee. Mr. Raspino’s career has spanned almost 40 years, most recently as president and chief executive officer of Pride International, Inc. (NYSE: PDE) until Pride’s merger with Ensco plc in May 2011. He will stand for election at the 2013 annual meeting of shareholders in June.

On May 3, 2013, we announced that the Board of Directors accepted the resignation of director Louis A. Simpson and that Thomas L. Ryan, President and Chief Executive Officer of Service Corporation International (NYSE:SCI), had been appointed to fill the vacancy and has been appointed to the audit committee. He will stand for election at the 2013 annual meeting of shareholders in June. Mr. Ryan replaces R. Brad Martin on the audit committee, with Mr. Martin becoming chair of the nominating, corporate governance and social responsibility committee.

Results of Board Review

On February 20, 2013, we announced that our Board of Directors had received the results of its previously announced review of the financing arrangements between Mr. McClendon (and the entities through which he participates in the Founder Well Participation Program (FWPP)) and third parties identified as having a financial relationship with us, as well as other matters. The review was led by the Audit Committee of the Board with the assistance of independent counsel retained by the independent members of the Board in April 2012. In connection with the review, millions of pages of documents were collected and reviewed and more than 50 interviews of Chesapeake and third-party personnel were conducted.

Among the transactions reviewed were the 2008-2012 financing arrangements between EIG Global Energy Partners (EIG) and affiliates of Mr. McClendon regarding financing of his participation in the FWPP, as well as the preferred stock investments by EIG in CHK Utica, L.L.C. and CHK Cleveland Tonkawa, L.L.C. See Noncontrolling Interests in Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part 1 of this report for further discussion of the preferred stock investment transactions. The review of the financing arrangements did not reveal any improper benefit to Mr. McClendon or increased cost to the Company as a result of the overlap in the financial relationships.

The review also covered:

- other relationships in which both Mr. McClendon and the Company conducted business with the same financial institutions;
- the trading activities of the Heritage Hedge Fund (co-founded by Mr. McClendon) through 2007, when the Heritage Hedge Fund ceased operations; and
- other matters, including issues regarding administration of the FWPP, and a 1998 loan to Mr. McClendon by then Board member Frederick B. Whittemore.

Based on the documents reviewed and interviews conducted, no intentional misconduct by Mr. McClendon or any of the Company's management was found by the Board concerning these relationships and/or these transactions and issues.

We also announced on February 20, 2013 that our Board of Directors had concluded that the Company did not violate antitrust laws in connection with the acquisition of Michigan oil and gas rights in 2010. As described in Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, in June 2012 we received a subpoena from the Antitrust Division, Midwest Field Office, of the United States Department of Justice, and demands for documents and information from state governmental agencies, investigating possible antitrust violations arising from 2010 leasing activities. The Board commenced its own investigation of these allegations in June 2012 and based its conclusion on a thorough review conducted independently by outside counsel and cooperation with the Department of Justice.

Senior Notes Offering; Tender Offers; Redemption of 6.775% Senior Notes due 2019

On April 1, 2013, we issued $2.3 billion in aggregate principal amount of senior notes at par. The offering included three series of notes: $500 million in aggregate principal amount of 3.25% Senior Notes due 2016; $700 million in aggregate principal amount of 5.375% Senior Notes due 2021; and $1.1 billion in aggregate principal amount of 5.75% Senior Notes due 2023. We used a portion of the net proceeds of $2.277 billion to purchase outstanding senior notes through tender offers we commenced concurrently with the senior notes offering. We purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to those tender offers, which expired April 12, 2013. We will record a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million in deferred charges. We plan to use a substantial portion of the remaining net proceeds from the offering to redeem $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 (the “2019 Notes”) at par pursuant to notice of special early redemption. As described in the following paragraph, the notice has been the subject of recent litigation. Any proceeds remaining will be used to repay and/or retire at maturity all outstanding 7.625% Senior Notes due 2013 and to purchase, repay and/or redeem over time other outstanding indebtedness, including indebtedness outstanding under our corporate revolving bank credit facility.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York against The Bank of New York Mellon Trust Company, N.A. (BNY Mellon), the indenture trustee for the 2019 Notes. The Company sought a declaration that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par on May 13, 2013 (plus interest accrued to that date) was timely and effective pursuant to the “Special Early Redemption” provision of the supplemental indenture governing the 2019 Notes. BNY Mellon asserted that the March 15, 2013 notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose and because of the specific phrasing in the notice that provides that it will not be effective unless the Court concluded it was timely. The Court conducted a trial on the matter in late April and on May 8, 2013, ruled in the Company's favor. Accordingly, the Company is proceeding with its redemption of the 2019 Notes at par, with payment to be made on May 13, 2013 pursuant to the terms of the notice. The Company intends to proceed with the redemption even if BNY Mellon appeals the Court's ruling, unless the Court's ruling is stayed.

Recent and Planned Sales

An essential part of our business strategy in 2013 is using the proceeds from sales to fund the capital expenditures needed to transition from a natural gas-focused drilling program to a liquids-focused drilling program and to reduce our indebtedness.

Recent Sales

On March 8, 2013, our wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), sold its interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP for consideration of approximately $134 million in cash.

On May 8, 2013, CMD sold its wholly owned subsidiary, Granite Wash Midstream Gas Services, L.L.C. (GWMGS), to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE), for consideration of approximately $245 million in cash, subject to post-closing adjustments. GWMGS owns certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE includes long-term fee-based agreements for gas gathering, compression, treating and processing services.

Through May 9, 2013, inclusive of the transactions noted above, we sold natural gas and oil properties, midstream and other assets that were noncore or do not fit our long-term plans for proceeds of approximately $895 million, approximately $366 million of which closed in the Current Quarter. Also, see Note 8 of the notes to our condensed consolidated financial statements for a discussion of the drilling carries we continue to receive through our joint ventures.

Planned Sales

On February 25, 2013, we entered into an agreement whereby Sinopec International Petroleum Exploration and Production Corporation (Sinopec) will purchase a 50% undivided interest in 850,000 of our net oil and natural gas leasehold acres in the Mississippi Lime play in northern Oklahoma (425,000 acres net to Sinopec). The total consideration for the transaction will be $1.02 billion in cash, of which approximately 93% will be received upon closing. Payment of the remaining proceeds will be subject to certain customary title contingencies. Production from these assets (including Mississippi Lime and other formations), net to our interest and prior to Sinopec's purchase, averaged approximately 34 thousand barrels of oil equivalent per day in the 2012 fourth quarter and, as of December 31, 2012, there were approximately 140 million barrels of oil equivalent of net proved reserves associated with the assets. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved. As the operator of the project, we will conduct all leasing, drilling, completion, operations and marketing for the joint venture. The transaction is anticipated to be completed in the 2013 second quarter.

On April 30, 2013, CMD entered into an agreement to sell its wholly owned midstream subsidiary, Mid-America Midstream Gas Services, L.L.C. (MAMGS), to Semgas, L.P. (SemGroup), a wholly owned subsidiary of SemGroup Corporation, for consideration of approximately $300 million in cash, subject to post-closing adjustments. MAMGS owns certain gathering and processing assets located in the Mississippi Lime play, and the transaction with SemGroup will include a new long-term fee-based gathering and processing agreement covering acreage dedication areas in the Mississippi Lime play. The sale is expected to close in the 2013 second quarter, subject to certain regulatory approvals and closing conditions.

In addition to the Mississippi Lime joint venture and Mississippi Lime midstream sale, we expect to sign agreements to sell our northern Eagle Ford Shale assets and other noncore properties during the 2013 second quarter. We do not have binding agreements for all of our planned asset sales and our ability to consummate each of these transactions is subject to changes in market conditions and other factors beyond our control.

Liquidity and Capital Resources

Liquidity Overview

As of March 31, 2013, we had approximately $3.262 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving bank credit facilities) compared to $4.338 billion as of December 31, 2012. As of March 31, 2013, we had negative working capital of approximately $2.901 billion compared to negative working capital of approximately $3.318 billion as of December 31, 2012. Working capital deficits have historically existed largely because our capital spending generally has exceeded our cash flow from operations.

Our business is capital intensive. We project that our capital expenditures will continue to exceed our operating cash flow in 2013, although by a significantly smaller amount than in 2012. We are continuing our transition to an asset base more balanced between natural gas and oil from one primarily focused on natural gas. We are also shifting our focus to developing our high-quality asset base after approximately a decade of asset accumulation. We also expect to benefit from operating efficiencies associated with our strategy of developing the core of the core of our substantial leasehold position.

During the Current Quarter, our capital expenditures exceeded cash flow from operations, and we filled this spending “gap” with borrowings and proceeds from sales of assets that we determined were noncore or did not fit our long-term plans. During the Current Quarter, we increased our debt, net of unrestricted cash, by approximately $1.083 billion, to $13.416 billion.

Our 2013 capital expenditure budget is approximately 50% less than our 2012 capital expenditures, and as operator of a substantial portion of our natural gas and oil properties under development, we have significant control and flexibility over the development plan and the associated timing of activity, enabling us to expeditiously reduce at least a portion of our capital spending if needed. To mitigate our downside exposure to lower commodity prices, we have hedged, in the form of over-the-counter derivative contracts, approximately 84% of our remaining forecasted 2013 natural gas, oil and NGL revenue, including downside price protection on approximately 78% of our remaining 2013 estimated natural gas production at an average price of $3.72 per mcf and 88% of our remaining 2013 estimated oil production at an average price of $95.43 per bbl. Hedging allows us to reduce the effect of price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization). Based on our forecasted operating cash flow for 2013, which takes into account our current hedges, and considering our 2013 forecasted capital expenditures, we are expecting a funding gap of approximately $3.5 billion for 2013. We plan to fill the funding gap principally with the proceeds from planned sales of certain of our natural gas and oil properties, midstream and other assets and expect those total proceeds to be $4 - $7 billion in 2013. Through May 9, 2013, we have closed or have binding agreements on approximately $2.3 billion of asset sales and have multiple other transactions in advanced stages of negotiation. Asset sales are uncertain and subject to changes in market conditions and other factors beyond our control. Any remaining cash available after applying these proceeds to the deficit between capital expenditures and operating cash flow will be available to reduce our long-term debt. In addition, we believe we will have sufficient liquidity to fill any remaining funding gap with borrowing capacity under our corporate revolving bank credit facility.

As part of our sales planning and capital expenditure budgeting process, we closely monitor the resulting effects on the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our corporate revolving bank credit facility. While asset sales enhance our ability to reduce debt, sales of producing natural gas and oil properties may adversely affect the amount of cash flow and EBITDA we generate and reduce the amount and value of collateral available to secure our obligations, both of which can be exacerbated by low prices for our production. In September 2012, we obtained an amendment to our corporate revolving bank credit facility agreement that relaxed the required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. See Bank Credit Facilities - Corporate Credit Facility below for discussion of the terms of the amendment. Without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance, primarily because the closing of certain asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. As of March 31, 2013, we were in compliance with the current covenants and would have also been in compliance with the more restrictive covenants that existed prior to the amendment. Failure to maintain compliance with the covenants of our revolving bank credit facility agreement could result in the acceleration of outstanding indebtedness under the facility and lead to cross defaults under our senior note and contingent convertible senior note indentures, secured hedging facility, equipment master lease agreements and term loan.

We expect to have adequate liquidity to repay the remaining outstanding amount of our senior note indebtedness that matures in 2013 and to reduce additional indebtedness using proceeds from our April 1, 2013 issuance of $2.3 billion aggregate principal amount of senior notes (see Recent Developments above for further discussion). Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various arrangements, agreements and investments described in Contractual Obligations and Off-Balance Sheet Arrangements below and in Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, recognizing that we may be required to meet such commitments even if our business plan assumptions were to change due to circumstances beyond our control.

Based upon our capital expenditure budget, our forecasted operating cash flow, projected levels of indebtedness and binding purchase and sale agreements for certain future asset sales, we are projecting that we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility, and we will have adequate liquidity, through the 2014 first quarter. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures and other spending, to adapt to potential negative developments if needed.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Quarter and the Prior Quarter. See Recent and Planned Sales above and Notes 6, 8 and 11 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of sales of natural gas and oil assets, sales of other assets and sales of preferred interests and noncontrolling interests in subsidiaries.

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Cash provided by operating activities[(a)]	$924	$274
Sales of natural gas and oil assets:		
Volumetric production payment	—	744
Joint venture leasehold	25	18
Other natural gas and oil properties	165	59
Total sales of natural gas, oil and other assets	190	821
Other sources of cash and cash equivalents:		
Sales of other property and equipment	201	48
Sale of preferred interest and ORRI in CHK C-T	—	1,250
Proceeds from long-term debt	—	1,263
Proceeds from credit facilities borrowings, net	821	1,142
Other	56	19
Total other sources of cash and cash equivalents	1,078	3,722
Total sources of cash and cash equivalents	$2,192	$4,817

(a) Includes cash settlements of derivative instruments classified as operating cash flows.

Cash provided by operating activities is a source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $924 million in the Current Quarter compared to $274 million in the Prior Quarter. The increase in cash provided by operating activities from the Prior Quarter to the Current Quarter is primarily the result of an increase in realized natural gas, oil and NGL prices (excluding the effect of unrealized gains or losses on derivatives) from $4.02 per mcfe in the Prior Quarter to $4.46 per mcfe in the Current Quarter, an increase in sales volumes and decreases in certain of our operating expenses per unit. 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, impairments of natural gas and oil properties and other assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under Results of Operations.

During the Prior Quarter, we issued $1.3 billion of 6.775% Senior Notes due 2019 in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility. On March 15, 2013, we provided notice to the trustee of our election to redeem the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest on May 13, 2013. See additional discussion above under Recent Developments.

Our $4.0 billion corporate revolving bank credit facility, our $500 million oilfield services revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use these revolving bank credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $3.632 billion and repaid $2.811 billion in the Current Quarter and borrowed $5.688 billion and repaid $4.546 billion in the Prior Quarter 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 is 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. We believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our oilfield services facility is secured by substantially all of our wholly owned oilfield services assets and is not subject to periodic borrowing base redeterminations. Prior to June 15, 2012, we also had a $600 million midstream revolving bank credit facility, which we terminated in June 2012. Our revolving bank credit facilities are described below under Bank Credit Facilities.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the Current Quarter and the Prior Quarter:

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Natural Gas and Oil Expenditures:		
Drilling and completion costs[(a)(b)]	$(1,566)	$(2,503)
Acquisitions of proved properties	(3)	(5)
Acquisitions of unproved properties	(70)	(968)
Geological and geophysical costs[(b)]	(13)	(71)
Interest capitalized on unproved properties	(207)	(162)
Total natural gas and oil expenditures	(1,859)	(3,709)
Other Uses of Cash and Cash Equivalents:		
Additions to other property and equipment	(330)	(690)
Cash paid for prepayment of mortgage	(55)	—
Dividends paid	(101)	(99)
Distributions to noncontrolling interest owners	(57)	(39)
Cash paid for financing derivatives[(c)]	(11)	(9)
Additions to investments	(3)	(73)
Other	(30)	(111)
Total uses of cash and cash equivalents	$(2,446)	$(4,730)

(a) Net of $180 million and $448 million in drilling and completion carries received from our joint venture partners during the Current Quarter and the Prior Quarter, respectively.

(b) Includes related capitalized interest.

(c) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. Drilling and completion costs during the Current Quarter reflected the impact of a reduction in the amount of drilling and completion carries received from our joint venture partners. During the 2012 first quarter, our operated rig count was as high as 165 rigs as we were quickly ramping up our liquids-focused drilling while, at the same time, we were gradually ramping down drilling of natural gas wells. During the Current Quarter, our average rig count was 83 operated rigs, and as of May 9, 2013, our rig count was 79 operated rigs. Our natural gas drilling activities have been sharply reduced since 2012, from 50 rigs at the beginning of 2012 to an average of 9 rigs in the Current Quarter. The Prior Quarter drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled, but not completed, in prior periods. These completions, which represented approximately 90% of the natural gas wells we completed during the Prior Quarter, enabled us to hold by production the related leasehold according to the terms of our leases. Our unproved property leasehold acquisition costs during the Prior Quarter were $968 million, approximately 60% of which were focused on adding to our acreage in the Utica and Mississippi Lime plays to complete our leasehold acquisition strategies in connection with completed or planned joint ventures in these areas. Capital expenditures related to additions to property and equipment associated with our midstream, oilfield services and other fixed assets of $690 million during the Prior Quarter were primarily related to the expansion of our gathering systems and the growth of our oilfield services businesses, in particular our hydraulic fracturing business. The reduction of $360 million in the Current Quarter is primarily the result of our sale of substantially all of our midstream business in December 2012.

We paid dividends on our common stock of $58 million and $56 million in the Current Quarter and the Prior Quarter, respectively. We paid dividends on our preferred stock of $43 million in the Current Quarter and the Prior Quarter.

Bank Credit Facilities

During the Current Quarter, we used two revolving bank credit facilities as sources of liquidity.

	Corporate Credit Facility[a]	Oilfield Services Credit Facility[b]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of March 31, 2013	$832	$408
Letters of credit outstanding as of March 31, 2013	$31	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

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

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 proved reserves and bear interest at a variable rate. We were in compliance with all covenants under the amended agreement as of March 31, 2013. For further discussion on the terms of our corporate credit facility, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

As described above in Liquidity Overview, in September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. The amendment, among other things, adjusts our required indebtedness to EBITDA ratio covenant through the earlier of (i) December 31, 2013 and (ii) the date on which we elect to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the “Amendment Effective Period”). The amendment increased the maximum indebtedness to EBITDA ratio as of September 30, 2012 from 4.00 to 1.00 to 6.00 to 1.00 and revised the required ratio for the next four quarters as shown below. The ratio returns to 4.00 to 1.00 as of December 31, 2013 and thereafter.

Effective Date	Amended Indebtedness to EBITDA Ratio
December 31, 2012	5.00 to 1.00
March 31, 2013	4.75 to 1.00
June 30, 2013	4.50 to 1.00
September 30, 2013	4.25 to 1.00

Our actual indebtedness to EBITDA ratio as of March 31, 2013 was approximately 3.62 to 1.00. The ratio compares consolidated indebtedness to consolidated EBITDA, both non-GAAP financial measures that are defined in the credit facility agreement, for the 12-month period ending on the measurement date. Consolidated indebtedness consists of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA consists of the net income of Chesapeake and certain of our subsidiaries, excluding income from investments and non-cash income plus interest expense, taxes, depreciation, amortization expense and other non-cash expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other changes.

The credit facility amendment increases the applicable margin by 0.25% for borrowings under the corporate credit facility on each day during the Amendment Effective Period when credit extensions exceed 50% of the borrowing capacity and requires us to pay a fee to each lender in an amount equal to 0.05% of its revolving commitment if the Amendment Effective Period is in effect on June 30, 2013. Based on current commitment levels, this would result in an additional payment of $2 million. In addition, the amendment does not allow our collateral value securing the borrowings to be more than $75 million below the collateral value that was in effect as of September 30, 2012 during the Amendment Effective Period.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. The facility may be expanded from $500 million to $900 million at COO’s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, which are unrestricted subsidiaries under Chesapeake’s senior notes, contingent convertible senior notes, term loan, corporate revolving bank credit facility, secured hedging facility and equipment master lease agreements), and bear interest at a variable interest rate. For further discussion of the terms of our oilfield services credit facility, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Midstream Credit Facility. Prior to June 15, 2012, we utilized a $600 million syndicated senior secured revolving bank credit facility to fund capital expenditures to build natural gas gathering and other systems in support of our drilling program and for general corporate purposes associated with our midstream operations. With the then anticipated sale of the substantial majority of our midstream business in the second half of 2012, on June 15, 2012, we paid off and terminated our midstream credit facility.

Hedging Facility

We have a multi-counterparty secured hedging facility with 17 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.25 billion under the terms of the facility. For further discussion of the terms of our hedging facility, see Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Term Loan

November 2012 Term Loan. In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion (November 2012 term loan). Our obligations under the facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the facility bear interest at our option, at either (i) the Eurodollar rate, which is based on LIBOR, plus a margin of 4.50% or (ii) a base rate equal to the greater of (a) the Bank of America, N.A. prime rate, (b) the federal funds effective rate plus 0.50% per annum and (c) the Eurodollar rate that would be applicable to a Eurodollar loan with an interest period of one month plus 1% per annum, in each case plus a margin of 3.50%. The Eurodollar rate is subject to a floor of 1.25% per annum and the base rate is subject to a floor of 2.25% per annum. The facility may be voluntarily repaid at a make-whole price in the first year, may be voluntarily repaid without penalty in the second and third years at par plus a specified call premium and may be voluntarily repaid at any time thereafter at par. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities and the November 2012 term loan discussed above, our long-term debt consisted of the following as of March 31, 2013:

	March 31, 2013 ($ in millions)
7.625% senior notes due 2013[(a)]	$464
9.5% senior notes due 2015	1,265
6.25% euro-denominated senior notes due 2017[(b)]	440
6.5% senior notes due 2017	660
6.875% senior notes due 2018[(a)]	474
7.25% senior notes due 2018	669
6.625% senior notes due 2019[(c)]	650
6.775% senior notes due 2019[(d)]	1,300
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[(e)]	396
2.5% contingent convertible senior notes due 2037[(e)]	1,168
2.25% contingent convertible senior notes due 2038[(e)]	347
Discount on senior notes[(f)]	(404)
Interest rate derivatives[(g)]	17
Total senior notes, net	$10,246

(a) See Recent Developments for further discussion of tender offers completed for a portion of these notes subsequent to March 31, 2013.

(b) The principal amount shown is based on the exchange rate of $1.2816 to €1.00 as of March 31, 2013. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our related foreign currency derivatives.

(c) Issuers are COO, an indirect wholly owned subsidiary of the Company, and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(d) In the Current Quarter, we issued notice to the trustee to redeem our 6.775% Senior Notes due 2019 at par. See Recent Developments for further discussion.

(e)

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.

(f) Included in this discount was $359 million as of March 31, 2013 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(g) See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for discussion related to these instruments.

For further discussion and details regarding our senior notes, contingent convertible senior notes and COO senior notes, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and 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. As of March 31, 2013, our natural gas, oil and interest rate derivative instruments were spread among 15 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.551 billion as of March 31, 2013) and exploration and production companies that own interests in properties we operate ($630 million as of March 31, 2013). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter and the Prior Quarter, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Contractual Obligations and Off-balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of March 31, 2013, these arrangements and transactions included (i) operating lease agreements, (ii) VPPs (to physically deliver and purchase volumes and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments and (viii) various other commitments we enter into in the ordinary course of business that could result in a future cash obligation.

As the operator of the properties from which VPP volumes have been sold, we have the responsibility to bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining the cost center ceiling for impairment purposes and in determining our standardized measure. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all. We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

See Notes 4, 8 and 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of commitments, VPPs and VIEs, respectively.

Results of Operations - Three Months Ended March 31, 2013 vs. March 31, 2012

General. For the Current Quarter, Chesapeake had net income of $102 million, or $0.02 per diluted common share, on total revenues of $3.424 billion. This compares to a net loss of $3 million, or $0.11 per diluted common share, on total revenues of $2.419 billion during the Prior Quarter.

Natural Gas, Oil and NGL Sales. During the Current Quarter, natural gas, oil and NGL sales were $1.453 billion compared to $1.068 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 358 bcfe at a weighted average price of $4.46 per mcfe, compared to 333 bcfe produced and sold in the Prior Quarter at a weighted average price of $4.02 per mcfe (weighted average prices exclude the effect of unrealized losses on derivatives of $146 million and $270 million in the Current Quarter and the Prior Quarter, respectively). The increase in the price received per mcfe in the Current Quarter compared to the Prior Quarter resulted in an increase in revenues of $159 million and increased sales volumes resulted in a $102 million increase in revenues, for a total increase in revenues of $261 million (excluding unrealized gains or losses on natural gas, oil and NGL derivatives). The increase in production from period to period was primarily generated through the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $2.13 compared to $2.35 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $94.85 and $92.63 in the Current Quarter and the Prior Quarter, respectively. NGL prices realized per barrel (excluding unrealized gains or losses on derivatives) were $28.25 and $33.60 in the Current Quarter and the Prior Quarter, respectively. Realized gains from our natural gas, oil and NGL derivatives resulted in a net increase in natural gas, oil and NGL revenues of $4 million, or $0.01 per mcfe, in the Current Quarter and a net increase of $117 million, or $0.35 per mcfe, in the Prior Quarter. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of March 31, 2013.

A change in natural gas, oil and NGL prices has a significant impact on our 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 $27 million and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $14 million without considering the effect of hedging activities.
The following tables show our production and average sales prices received by operating division for the Current Quarter and the Prior Quarter:

	Three Months Ended March 31, 2013								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	134.3	1.91	0.4	90.45	0.4	18.85	139.0	39	2.16
Northern	49.7	2.45	4.4	90.29	2.7	32.25	92.6	26	6.59
Eastern[c]	80.3	2.38	0.3	83.88	0.7	39.32	86.1	24	2.81
Western[d]	8.8	0.29	4.2	101.76	1.1	15.72	40.4	11	10.90
Total[e]	273.1	2.10	9.3	95.23	4.9	28.25	358.1	100 %	4.45

	Three Months Ended March 31, 2012								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	149.8	1.59	0.3	107.76	0.4	32.28	153.8	47	1.83
Northern	53.3	2.18	3.3	97.40	2.8	30.54	89.7	28	5.75
Eastern[c]	53.8	1.89	—	—	0.4	51.83	56.2	16	2.30
Western[d]	13.9	1.61	2.4	99.19	0.7	45.76	33.1	9	9.05
Total[e]	270.8	1.77	6.0	98.36	4.3	35.16	332.8	100 %	3.67

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

(b) 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 have resulted in lower natural gas price realizations in the Barnett Shale than in our other major natural gas plays.

(c) Our Eastern division primarily includes the Marcellus Shale, which held approximately 23% of our estimated proved reserves by volume as of December 31, 2012. Production for the Marcellus Shale for the Current Quarter and the Prior Quarter was 76.9 bcfe and 51.3 bcfe, respectively.

(d) Our Western division primarily includes the Eagle Ford Shale, which held approximately 21% of our estimated proved reserves by volume as of December 31, 2012. Production for the Eagle Ford Shale for the Current Quarter and the Prior Quarter was 36.5 bcfe and 11.3 bcfe, respectively.

As the Eagle Ford Shale continues to be a developing play where additional infrastructure is being added to meet the growing production, we experienced lower natural gas price realizations in the Current Quarter and Prior Quarter as a result of higher transportation costs compared to more developed plays.

(e) Current Quarter and Prior Quarter production reflects various asset sales. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our natural gas and oil property divestitures.

Our average daily production of 3.979 bcfe for the Current Quarter consisted of approximately 3.035 bcf of natural gas (76% on a natural gas equivalent basis) and approximately 157,390 bbls of liquids, consisting of approximately 103,145 bbls of oil (16% on a natural gas equivalent basis) and approximately 52,245 bbls of NGL (8% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 2%, our year-over-year growth rate of oil production was 56% and our year-over-year growth rate of NGL production was 14%.

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 primarily for owners in Chesapeake-operated wells. Chesapeake recognized $1.781 billion in marketing, gathering and compression sales in the Current Quarter with corresponding expenses of $1.745 billion, for a net margin before depreciation of $36 million. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. This compares to sales of $1.216 billion, expenses of $1.197 billion and a net margin before depreciation of $19 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 oil volumes marketed and an increase in compression services, offset by the loss of activity from the sale of substantially all of our gathering business in the 2012 fourth quarter. Our gathering business provided approximately $5 million and $9 million of the total marketing, gathering and compression net margin, or 14% and 48% in the Current Quarter and the Prior Quarter, respectively.

Oilfield Services Revenues and Expenses. Oilfield services consist of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $190 million in oilfield services revenues in the Current Quarter with corresponding expenses of $155 million, for a net margin before depreciation of $35 million. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our oilfield services assets. This compares to revenue of $135 million, expenses of $96 million and a net margin before depreciation of $39 million in the Prior Quarter. Oilfield services revenues and expenses increased from the Prior Quarter to the Current Quarter primarily as a result of the growth in our hydraulic fracturing business; however, these increases were offset by losses recognized in the Current Quarter related to certain consolidated investments.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $307 million in the Current Quarter, compared to $349 million in the Prior Quarter, respectively. On a unit-of-production basis, production expenses were $0.86 per mcfe in the Current Quarter compared to $1.05 per mcfe in the Prior Quarter, respectively. The per unit expense decrease in the Current Quarter was primarily the result of the divestiture of our Permian Basin assets in the 2012 fourth quarter, which had higher per unit costs, and a $15 million fee retroactively imposed in the Prior Quarter in Pennsylvania on drilled wells, which had a $0.05 per mcfe effect. Production expenses in the Current Quarter and the Prior Quarter included approximately $38 million and $59 million, or $0.11 and $0.18 per mcfe, respectively, associated with VPP production volumes.

Production Taxes. Production taxes were $53 million in the Current Quarter compared to $47 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.15 per mcfe in the Current Quarter compared to $0.14 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, oil and NGL prices are higher. The $6 million increase in production taxes in the Current Quarter was primarily due to the increase in the unhedged price of our production from $3.67 per mcfe to $4.45 per mcfe, in addition to an increase in production of 25 bcfe. Production taxes in the Current Quarter and the Prior Quarter included approximately $5 million and $6 million, or $0.01 and $0.02 per mcfe, respectively, associated with VPP production volumes.

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 $110 million in the Current Quarter and $136 million in the Prior Quarter. General and administrative expenses were $0.31 and $0.41 per mcfe for the Current Quarter and the Prior Quarter, respectively. The per unit expense decrease in the Current Quarter was primarily due to our cost structure initiative and increased emphasis on operational efficiencies, offset by an increase in legal expenses relating to various corporate matters. Included in general and administrative expenses is stock-based compensation of $20 million in the Current Quarter and $19 million in the

Prior Quarter. See Note 6 for further discussion 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, divestiture, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with acquisition of leasehold, 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 $92 million and $115 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, divestiture, drilling and completion efforts and the construction of our property, plant and equipment.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $648 million and $506 million in the Current Quarter and the Prior Quarter, respectively. The $142 million increase in the Current Quarter is primarily the result of an 8% increase in production in the Current Quarter compared to the Prior Quarter and the higher production costs of liquids-rich plays compared to natural gas plays as we shift to a more liquids-focused strategy. 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 $1.81 and $1.52 in the Current Quarter and the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $78 million in the Current Quarter, compared to $84 million in the Prior Quarter. Depreciation and amortization of other assets was $0.22 and $0.25 per mcfe in the Current Quarter and the Prior Quarter, respectively. The per unit decrease in the Current Quarter is primarily due to an increase in production in the Current Quarter compared to the Prior Quarter and the sale of substantially all of our midstream business in December 2012. See Note 1 of the notes to our consolidated financial statements included in Item 1 of Part I of this report for information regarding our assets held for sale.

Property and equipment costs are depreciated on a straight-line basis and are depreciated over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment are used to drill and complete our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as drilling and completion costs. The following table shows the estimated useful life of our assets and depreciation expense by asset class for the Current Quarter and Prior Quarter.

	Three Months Ended March 31,		Useful
	2013	2012	Life
	($ in millions)		(in years)
Oilfield services equipment[(a)]	$23	$13	3 - 15
Natural gas gathering systems and treating plants[(b)]	3	18	20
Buildings and improvements	13	10	10 - 39
Natural gas compressors[(b)]	9	5	3 - 20
Computers and office equipment	12	11	3 - 7
Vehicles	11	12	0 - 5
Other	7	15	2 - 20
Total depreciation and amortization of other assets	$78	$84	

(a) Included in our oilfield services operating segment.
(b) Included in our marketing, gathering and compression operating segment.

Gains on Sales of Fixed Assets. In the Current Quarter, net gains on sales of fixed assets were $49 million compared to net gains of $2 million in the Prior Quarter. See Note 11 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our gains and losses on sales of fixed assets.

Impairments of Fixed Assets and Other. In the Current Quarter, we recognized $27 million of impairment losses associated with land and buildings currently classified as held for sale. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our impairments of fixed assets and other.

Employee Retirement and Other Termination Benefits. We recorded $133 million of employee retirement and other termination benefits in the Current Quarter primarily related to our voluntary separation plan and senior management separations. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

Interest Expense. Interest expense was $21 million in the Current Quarter compared to $12 million in the Prior Quarter as follows:

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Interest expense on senior notes	$186	$174
Interest expense on credit facilities	12	21
Interest expense on term loan	29	—
Realized (gains) losses on interest rate derivatives	(2)	—
Unrealized (gains) losses on interest rate derivatives	6	4
Amortization of loan discount, issuance costs and other	19	1
Capitalized interest	(229)	(188)
Total interest expense	$21	$12
Average senior notes borrowings	$10,283	$10,152
Average term loan borrowings	$2,000	$—
Average credit facilities borrowings	$1,095	$3,424

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.04 per mcfe in the Current Quarter compared to $0.02 per mcfe in the Prior Quarter.

Losses on Investments. Losses on investments were $27 million in the Current Quarter, compared to losses on investments of $5 million in the Prior Quarter. The Current Quarter loss related to our equity in the net losses of certain investments, primarily FTS International, Inc. (FTS). The Prior Quarter earnings related to our equity in the net losses primarily of FTS, offset by a gain related to our equity in the net income of ACMP.

Other Income. Other income was $6 million in both the Current Quarter and the Prior Quarter and consisted of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $63 million in the Current Quarter compared to an income tax benefit of $2 million in the Prior Quarter. Our effective income tax rate was 38% in the Current Quarter and 39% in the Prior Quarter. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded $44 million and $25 million of net income attributable to noncontrolling interests in the Current Quarter and the Prior Quarter, respectively. In the Current Quarter, net income attributable to noncontrolling interests was related to third-party ownership in CHK Utica, CHK C-T, the Chesapeake Granite Wash Trust and our consolidated investments in Wireless Seismic, Inc. and Big Star Crude Co., LLC In the Prior Quarter, net income attributable to noncontrolling interests was related to third-party ownership in CHK Utica and the Chesapeake Granite Wash Trust. CHK Utica and the Chesapeake Granite Wash Trust were formed in the fourth quarter of 2011 and CHK C-T was formed in the first quarter of 2012. We began consolidating our investments in Wireless Seismic, Inc. and Big Star Crude Co., LLC in the fourth quarter of 2012. Subsequent to March 31, 2013, we purchased approximately 15% of the outstanding CHK Utica preferred shares from existing investors for $213 million. See Note 18 of the notes to our condensed consolidated financial statements for further discussion of this transaction.

Application of Critical Accounting Policies

We consider accounting policies related to natural gas and oil properties, derivatives, variable interest entities 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 2012 Form 10-K.

Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards:

Recently Adopted Accounting and Disclosure Changes

In February 2012, the FASB issued guidance changing the presentation and disclosure of significant reclassifications out of accumulated other comprehensive income when required to be reclassified to net income entirely. This standard became effective for us on January 1, 2013 and did not have a significant impact on our financial statement presentation, financial position, results of operations or liquidity.

In December 2011 and January 2013, the FASB issued guidance amending and expanding disclosure requirements about the nature of an entity's rights of offset and related arrangements associated with its derivatives. Both standards became effective for us on January 1, 2013. This guidance did not have a significant impact on our financial statement presentation, financial position, results of operations or liquidity.

Recently Issued Accounting and Disclosure Change

In February 2013, the FASB issued guidance on the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. This standard will become effective for us on January 1, 2014 and we do not expect it to have a significant impact on our financial statement presentation, financial position, results of operations or liquidity.

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 (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, oil and NGL production and future expenses, estimated operating costs, assumptions regarding future natural gas, oil and NGL prices, planned drilling activity and drilling and completion capital expenditures (including the use of joint venture drilling carries), and anticipated sales, as well as statements concerning anticipated cash flow and liquidity, covenant compliance, debt reduction, business strategy and other plans and objectives for future operations. Pending sales transactions are subject to closing conditions and may not be completed in the time frame anticipated. We do not have binding agreements for all of our planned asset sales. Our ability to consummate each of these transactions is subject to changes in market conditions and other factors. If one or more of the transactions is not completed in the anticipated time frame, or at all, or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness as planned could be adversely affected. For sales transactions that have closed, we may not be able to satisfy all the requirements necessary to receive proceeds subject to title and other contingencies. 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 our 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 2012 Form 10-K and include:

- the volatility of natural gas, oil and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values;
- the availability of capital on an economic basis, including through planned sales, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;

- hedging activities resulting in lower prices realized on natural gas, oil and NGL sales;
- the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations;
- drilling and operating risks, including potential environmental liabilities;
- legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species;
- current worldwide economic uncertainty which may have a material adverse effect on our results of operations, liquidity and financial condition;
- oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow;
- losses possible from pending or future litigation and regulatory investigations;
- cyber attacks adversely impacting our operations; and
- a delay in naming a new CEO, the loss of key operational personnel or inability to maintain our corporate culture.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, 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, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective prices to be received for our production. 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, oil and NGL price changes is to hedge into strengthening natural gas and oil futures markets when prices reach levels that management believes are either unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. 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, options and swaptions. 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. We do this when we would be satisfied to sell our production at the price being capped by the call strike price or believe it would 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. In the second half of 2011 and in 2012, we bought natural gas and oil calls to, in effect, lock in sold call positions. Due to lower natural gas, oil and NGL prices, we were able to achieve this at a low cost to us. We deferred the payment of the premium on these trades to the related month of production being hedged. At times, we have taken advantage of attractive strip prices in out-years and sold natural gas and oil call options to our counterparties in exchange for near-term 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. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying condensed consolidated statement of cash flows.

We determine the volume we may potentially hedge by reviewing our overall 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 our forecasted production, and if production estimates are lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions are reversed. The actual fixed price on our derivative instruments is derived from bidding and

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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 are at 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. 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.

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 also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is 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. See Note 14 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the fair value measurements associated with our derivatives.

As of March 31, 2013, 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.
- Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.
- Swaptions: Chesapeake sells call swaptions to counterparties that allow them, on a specific date, to extend an existing fixed-price swap for a certain period of time.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our natural gas basis protection swaps 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. Our oil basis protection swaps 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.
- Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty’s downside exposure below the second put option.

As of March 31, 2013, we had the following open natural gas and oil derivative instruments:

	Volume (tbtu)	Weighted Average Price Fixed	Call (per mmbtu)	Put	Differential	Fair Value Asset (Liability) ($ in millions)
Natural Gas:						
Swaps:						
Q2 2013	171	$3.72	$—	$—	$—	$(52)
Q3 2013	179	3.67	—	—	—	(80)
Q4 2013	179	3.67	—	—	—	(98)
2014	57	4.21	—	—	—	(3)
Call Options (sold):						
2013	203	—	6.39	—	—	(1)
2014	330	—	6.43	—	—	(16)
2015	226	—	6.31	—	—	(27)
2016	279	—	6.72	—	—	(53)
2017 – 2020	114	—	10.92	—	—	(12)
Call Options (bought)[(a)]:						
2013	(203)	—	6.39	—	—	(7)
2014	(330)	—	6.43	—	—	(24)
2015	(226)	—	6.31	—	—	(54)
2016	(200)	—	6.02	—	—	(39)
Basis Protection Swaps:						
2013	33	—	—	—	(0.21)	(1)
2014	28	—	—	—	(0.32)	(4)
2015	31	—	—	—	(0.34)	(3)
2016	4	—	—	—	(1.03)	(3)
2017 – 2022	5	—	—	—	(1.02)	(4)
3-Way Collars:						
Q2 2013	18	—	4.03	3.03 / 3.55	—	(2)
Q3 2013	18	—	4.03	3.03 / 3.55	—	(5)
Q4 2013	18	—	4.03	3.03 / 3.55	—	(7)
2014 – 2015	18	—	4.70	3.50 / 4.00	—	(1)
Total Natural Gas						$(496)

	Volume (mmbbl)	Weighted Average Price Fixed	Call (per bbl)	Put	Differential	Fair Value Asset (Liability) ($ in millions)
Oil:						
Swaps:						
Q2 2013	7.9	$95.55	$—	$—	$—	$(15)
Q3 2013	8.5	95.42	—	—	—	(14)
Q4 2013	8.8	95.33	—	—	—	(4)
2014 – 2015	18.6	93.54	—	—	—	16
Call Options (sold):						
2013	12.9	—	94.04	—	—	(86)
2014	16.9	—	96.92	—	—	(104)
2015	24.7	—	100.45	—	—	(152)
2016	18.9	—	104.71	—	—	(103)
2017	5.3	—	83.50	—	—	(67)
Call Options (bought)(b):						
2013	(7.0)	—	90.80	—	—	2
2014	(2.2)	—	94.91	—	—	(4)
Swaptions:						
2014	2.9	106.69	—	—	—	(4)
2015	2.4	106.61	—	—	—	(2)
Basis Protection Swaps:						
2013	3.2	—	—	—	11.82	(2)
	Total Oil					$(539)
	Total Natural Gas and Oil					$(1,035)

(a) Included in the fair value are deferred premiums of $8 million, $41 million, $82 million and $84 million which we will realize in 2013, 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $61 million and $19 million which we will realize in 2013 and 2014, respectively.

In addition to the open derivative positions disclosed above, as of March 31, 2013, we had $155 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas, oil and NGL sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below.

	March 31, 2013 ($ in millions)
Q2 2013	$35
Q3 2013	31
Q4 2013	22
2014	(165)
2015	216
2016 – 2022	16
Total	$155

The table below reconciles the changes in fair value of our natural gas, oil and NGL derivatives during the Current Quarter. Of the $1.035 billion fair value liability as of March 31, 2013, $417 million related to contracts maturing in the next 12 months and $618 million related to contracts maturing after 12 months. All open derivative instruments as of March 31, 2013 are expected to mature by December 31, 2022.

	2013
	($ in millions)
Fair value of contracts outstanding, as of January 1	$(924)
Change in fair value of contracts	(122)
Fair value of new contracts when entered into	—
Contracts realized or otherwise settled	11
Fair value of contracts when closed	—
Fair value of contracts outstanding, as of March 31	$(1,035)

The change in natural gas, oil and NGL prices during the Current Quarter increased the liability related to our derivative instruments by $122 million. This gain is recorded in natural gas, oil and NGL sales. We settled contracts that were in a liability position for $11 million. The realized gain is recorded in natural gas, oil and NGL 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 recognized in natural gas, oil and NGL 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 and settled values related to future production periods of derivatives not designated as cash flow hedges. As of March 31, 2013, we did not have any natural gas or oil derivatives that were designated as cash flow hedges.

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

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Natural gas, oil and NGL sales	$1,595	$1,221
Realized gains (losses) on natural gas, oil and NGL derivatives	4	117
Unrealized gains (losses) on natural gas, oil and NGL derivatives	(146)	(270)
Total natural gas, oil and NGL sales	$1,453	$1,068

Interest Rate Risk

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

	Years of Maturity						
	2013	2014	2015	2016	2017	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[a]	$464	$—	$1,661	$—	$2,269	$6,239	$10,633
Average interest rate	7.63 %	— %	7.89 %	— %	4.39 %	6.44 %	6.28 %
Debt – variable rate[b]	$—	$—	$832	$408	$2,000	$—	$3,240
Average interest rate	— %	— %	2.20 %	2.94 %	5.75 %	— %	4.48 %

(a) This amount does not include the discount included in debt of $404 million and interest rate derivatives of $17 million.

(b) This amount does not include the discount included in debt of $37 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 indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

Interest Rate Derivatives

To mitigate 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 March 31, 2013, 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 pre-determined swap with us on a specific date.

As of March 31, 2013, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Rate Fixed	Weighted Average Rate Floating[a]	Fair Value Hedge	Net Premiums	Fair Value Asset (Liability)
	($ in millions)				($ in millions)	
Fixed to Floating:						
Swaps						
Mature 2020 – 2021	$700	6.34 %	1 – 3 mL	No	$—	$(6)
Swaption						
Q2 2013	$125	6.13 %	3 mL	No	1	(2)
Floating to Fixed:						
Swaps						
Mature 2014 – 2015	$1,050	2.13 %	1 – 6 mL	No	—	(31)
					$1	$(39)

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

In addition to the open derivative positions disclosed above, as of March 31, 2013 we had $71 million of net gains related to settled derivative 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.

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

	Three Months Ended March 31,	
	2013	2012
	($ in millions)	
Interest expense on senior notes	$186	$174
Interest expense on credit facilities	12	21
Interest expense on term loans	29	—
Realized (gains) losses on interest rate derivatives	(2)	—
Unrealized (gains) losses on interest rate derivatives	6	4
Amortization of loan discount, issuance costs and other	19	1
Capitalized interest	(229)	(188)
Total interest expense	$21	$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. 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 are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $36 million as of March 31, 2013. The euro-denominated debt in long-term debt has been adjusted to $440 million as of March 31, 2013 using an exchange rate of $1.2816 to €1.00.

ITEM 4. Controls and Procedures

Evaluation of Disclosure 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. As of 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 Acting 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 Acting Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2013.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended March 31, 2013 which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

The Company is involved in a number of litigation and regulatory proceedings. Many of these proceedings are in early stages, and many of them seek an indeterminate amount of damages or penalties. See Litigation and Regulatory Proceedings and Environmental Risk in Note 4 of the notes to the condensed consolidated financial statements included in Item 1 of Part I of this report, which information is incorporated herein by reference, for a description of matters arising during the Current Quarter and new developments in previously reported proceedings.

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 2012 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

The following table presents information about repurchases of our common stock during the quarter ended March 31, 2013:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share [(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
January 1, 2013 through January 31, 2013	1,303,513	$16.96	—	—
February 1, 2013 through February 28, 2013	399,285	$20.48	—	—
March 1, 2013 through March 31, 2013	29,094	$20.04	—	—
Total	1,731,892	$17.82	—	—

(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 that is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of Company contributions.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits and Financial Statement Schedules

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	8/10/2009		
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	8/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/8/2012		
4.1	Fourteenth Supplemental Indenture dated May 18, 2013 among Chesapeake Energy Corporation, the Subsidiary Guarantors named therein and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated August 2, 2010.	S-3	333-168509	4.17	3/18/2013		

4.2	Fifteenth Supplemental Indenture dated April 1, 2013 among Chesapeake Energy Corporation, the Subsidiary Guarantors named therein and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated August 2, 2010 with respect to 3.25% Senior Notes due 2016.	8-A	001-13726	4.2	4/8/2013
4.3	Sixteenth Supplemental Indenture dated April 1, 2013 among Chesapeake Energy Corporation, the Subsidiary Guarantors named therein and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated as of August 2, 2010 with respect to 5.375% Senior Notes due 2021.	8-A	001-13726	4.3	4/8/2013

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.4	Seventeenth Supplemental Indenture dated April 1, 2013 among Chesapeake Energy Corporation, the Subsidiary Guarantors named therein and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated as of August 2, 2010 with respect to 5.75% Senior Notes due 2023.	8-A	001-13726	4.4	4/8/2013		
10.1	Form of Employment Agreement, effective January 1, 2013, between Chesapeake Energy Corporation and respective executive and senior vice presidents.	8-K	001-13726	10.1	1/7/2013		
10.2	Founder Separation and Services Agreement effective January 29, 2013 between Chesapeake Energy Corporation and Aubrey K. McClendon.	8-K	001-13726	10.1	4/19/2013		
10.3	Founder Joint Operating Services Agreement effective January 29, 2013 among Chesapeake Energy Corporation, Aubrey K. McClendon, Arcadia Resources, L.P., Larchmont Resources, L.L.C., Jamestown Resources, L.L.C. and Pelican Energy, L.L.C.	8-K	001-13726	10.2	4/19/2013		
10.4	Map Sale Rescission Agreement, effective as	8-K	001-13726	10.3	4/19/2013		

	of April 1, 2013, by and between Aubrey K. McClendon and Chesapeake Energy Corporation.	
10.5.1	Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan by and between Chesapeake Energy Corporation and Aubrey K. McClendon.	X
10.5.2	Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan by and between Chesapeake Energy Corporation and Aubrey K. McClendon.	X
10.5.3	2013 Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan by and between Chesapeake Energy Corporation and Aubrey K. McClendon	X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
31.1	Steven C. Dixon, Acting Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Steven C. Dixon, Acting 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						X	

	XBRL Taxonomy Extension Calculation Linkbase Document.	
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: May 10, 2013	By: /s/ STEVEN C. DIXON Steven C. Dixon Acting Chief Executive Officer and Chief Operating Officer
Date: May 10, 2013	By: /s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

INDEX TO EXHIBITS

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3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
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	Energy Corporation, the Subsidiary Guarantors named therein and Deutsche Bank Trust Company Americas, as Trustee, to Indenture dated August 2, 2010 with respect to 3.25% Senior Notes due 2016.				
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	Corporation.	
10.5.1	Restricted Stock Award Agreement for Amended and Restated Long Term Incentive Plan by and between Chesapeake Energy Corporation and Aubrey K. McClendon.	X
10.5.2	Nonqualified Stock Option Agreement for Amended and Restated Long Term Incentive Plan by and between Chesapeake Energy Corporation and Aubrey K. McClendon.	X
10.5.3	2013 Performance Share Unit Award Agreement for Amended and Restated Long Term Incentive Plan by and between Chesapeake Energy Corporation and Aubrey K. McClendon	X

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
31.1	Steven C. Dixon, Acting Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Steven C. Dixon, Acting 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						X	

	XBRL Taxonomy Extension Definition Linkbase Document.	
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X