CHESAPEAKE ENERGY CORP
Form 10-Q
November 09, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Quarterly Period Ended September 30, 2012
[ ] 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 November 2, 2012, there were 664,655,404 shares of our common stock, $0.01 par value, outstanding.

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PART I.
Financial Information

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

	September 30, 2012	December 31, 2011
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIEs)	$142	$351
Restricted cash	156	44
Accounts receivable	2,291	2,505
Short-term derivative assets	31	13
Deferred income tax asset	692	139
Other current assets	188	125
Current assets held for sale ($14 and $0 attributable to our VIEs)	111	—
Total Current Assets	3,611	3,177
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Evaluated natural gas and oil properties ($488 and $498 attributable to our VIEs)	51,014	41,723
Unevaluated properties	15,254	16,685
Natural gas gathering systems and treating plants	—	1,455
Oilfield services equipment	1,972	1,611
Other property and equipment	3,629	3,555
Total Property and Equipment, at Cost	71,869	65,029
Less: accumulated depreciation, depletion and amortization (($43) and ($6) attributable to our VIEs)	(33,573)	(28,290)
Property and equipment held for sale, net ($121 and $0 attributable to our VIEs)	2,307	—
Total Property and Equipment, Net	40,603	36,739
LONG-TERM ASSETS:		
Investments	647	1,531
Long-term derivative assets	6	—
Other long-term assets	681	388
Long-term assets held for sale	123	—
TOTAL ASSETS	$45,671	$41,835
CURRENT LIABILITIES:		
Accounts payable	$2,357	$3,311
Short-term derivative liabilities ($5 and $9 attributable to our VIEs)	150	191
Accrued interest	213	183
Current maturities of long-term debt, net	463	—
Other current liabilities ($20 and $23 attributable to our VIEs)	3,097	3,397
Current liabilities held for sale ($31 and $0 attributable to our VIEs)	176	—
Total Current Liabilities	6,456	7,082
LONG-TERM LIABILITIES:		
Long-term debt, net	15,755	10,626
Deferred income tax liabilities	3,418	3,484
Long-term derivative liabilities ($3 and $10 attributable to our VIEs)	999	1,541
Asset retirement obligations	353	323
Other long-term liabilities	997	818
Long-term liabilities held for sale	2	—

Total Long-Term Liabilities	21,524	16,792
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:		
666,955,284 and 660,888,159 shares issued	7	7
Paid-in capital	12,246	12,146
Retained earnings	241	1,608
Accumulated other comprehensive income (loss)	(188)	(166)
Less: treasury stock, at cost; 1,860,507 and 1,552,533 common shares	(41)	(33)
Total Chesapeake Stockholders’ Equity	15,327	16,624
Noncontrolling interests	2,364	1,337
Total Equity	17,691	17,961
TOTAL LIABILITIES AND EQUITY	$45,671	$41,835

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	($ in millions, except per share data)			
REVENUES:				
Natural gas, oil and NGL	$1,437	$2,402	$4,622	$4,688
Marketing, gathering and compression	1,381	1,422	3,710	3,844
Oilfield services	152	153	446	376
Total Revenues	2,970	3,977	8,778	8,908
OPERATING EXPENSES:				
Natural gas, oil and NGL production	320	282	1,005	782
Production taxes	53	50	141	140
Marketing, gathering and compression	1,339	1,392	3,631	3,744
Oilfield services	116	118	321	287
General and administrative	148	151	440	410
Natural gas, oil and NGL depreciation, depletion and amortization	762	423	1,856	1,147
Depreciation and amortization of other assets	66	75	233	206
Impairment of natural gas and oil properties	3,315	—	3,315	—
Losses on sales and impairments of fixed assets and other	45	3	286	7
Total Operating Expenses	6,164	2,494	11,228	6,723
INCOME (LOSS) FROM OPERATIONS	(3,194)	1,483	(2,450)	2,185
OTHER INCOME (EXPENSE):				
Interest expense	(36)	(4)	(63)	(37)
Earnings (losses) on investments	(23)	28	(87)	100
Gains on sales of investments	31	—	1,061	—
Losses on purchases or exchanges of debt	—	—	—	(176)
Other income (expense)	(9)	4	2	9
Total Other Income (Expense)	(37)	28	913	(104)
INCOME (LOSS) BEFORE INCOME TAXES	(3,231)	1,511	(1,537)	2,081
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	22	(1)	24	11
Deferred income taxes	(1,282)	590	(623)	801
Total Income Tax Expense (Benefit)	(1,260)	589	(599)	812
NET INCOME (LOSS)	(1,971)	922	(938)	1,269
Net income attributable to noncontrolling interests	(41)	—	(131)	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(2,012)	922	(1,069)	1,269
Preferred stock dividends	(43)	(43)	(128)	(128)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$(2,055)	$879	$(1,197)	$1,141
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$(3.19)	$1.38	$(1.86)	$1.79
Diluted	$(3.19)	$1.23	$(1.86)	$1.69
CASH DIVIDEND DECLARED PER COMMON SHARE	0.0875	0.0875	0.2625	0.25

WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	644	638	643	636
Diluted	644	753	643	752

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	($ in millions)			
NET INCOME (LOSS)	$(1,971)	$922	$(938)	$1,269
Other comprehensive income (loss), net of income tax:				
Unrealized gain (loss) on derivative instruments, net of income taxes of $1 million, $44 million, $1 and $133 million	3	72	3	218
Reclassification of gain on settled derivative instruments, net of income taxes of ($3) million, ($49) million, ($10) million and ($88) million	(6)	(80)	(18)	(144)
Ineffective portion of derivatives designated as cash flow hedges, net of income taxes of $0, $2 million, $0 and ($5) million	—	3	—	(8)
Unrealized gain (loss) on investments, net of income taxes of ($2) million, ($1) million, ($4) million and ($2) million	(3)	(1)	(7)	(4)
Other comprehensive income (loss)	(6)	(6)	(22)	62
COMPREHENSIVE INCOME (LOSS)	(1,977)	916	(960)	1,331
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(41)	—	(131)	—
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(2,018)	$916	$(1,091)	$1,331

The accompanying notes are an integral part of these condensed consolidated financial statements.
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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2012	2011
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$(938)	$1,269
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	2,089	1,353
Deferred income tax expense (benefit)	(623)	801
Unrealized (gains) losses on derivatives	(440)	456
Stock-based compensation	93	119
Losses on sales and impairments of fixed assets	262	7
Impairment of natural gas and oil properties	3,315	—
(Gains) losses on investments	147	(19)
Gains on sales of investments	(1,061)	—
Other	80	12
Changes in assets and liabilities	(946)	(274)
Cash provided by operating activities	1,978	3,724
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(7,525)	(5,345)
Acquisitions of proved and unproved properties	(2,813)	(3,773)
Proceeds from divestitures of proved and unproved properties	2,445	6,357
Additions to other property and equipment	(1,916)	(1,416)
Proceeds from sales of other assets	219	682
Proceeds from (additions to) investments	(261)	126
Proceeds from sale of midstream investment	2,000	—
Acquisition of drilling company	—	(339)
Increase in restricted cash	(280)	—
Other	(23)	(7)
Cash used in investing activities	(8,154)	(3,715)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	13,986	11,914
Payments on credit facilities borrowings	(13,614)	(12,057)
Proceeds from issuance of term loans, net of discount and offering costs	3,789	—
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	977
Cash paid to purchase debt	—	(2,015)
Cash paid for common stock dividends	(170)	(151)
Cash paid for preferred stock dividends	(128)	(128)
Cash (paid) received on financing derivatives	(36)	1,085
Proceeds from sales of noncontrolling interests	1,056	—
Proceeds from other financings	225	—
Distributions to noncontrolling interest owners	(163)	—
Net increase (decrease) in outstanding payments in excess of cash balance	(159)	489
Other	(68)	(114)

Cash provided by financing activities	5,981	—
Change in cash and cash equivalents classified as current assets held for sale	(14)	—
Net increase (decrease) in cash and cash equivalents	(209)	9
Cash and cash equivalents, beginning of period	351	102
Cash and cash equivalents, end of period	$142	$111

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)

	Nine Months Ended September 30,	
	2012	2011
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF NET CASH PAYMENTS (REFUNDS) FOR:		
Interest, net of capitalized interest	$—	$18
Income taxes, net of refunds received	$31	$(25)

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

Dividends payable on our common and preferred stock were $99 million as of September 30, 2012 and 2011.

For the nine months ended September 30, 2012 and 2011, natural gas and oil properties decreased by $103 million and increased by $148 million, respectively, as a result of an increase or decrease in accrued acquisition, drilling and completion costs.

For the nine months ended September 30, 2012 and 2011, other property and equipment was adjusted by $57 million and $90 million, respectively, as a result of an increase in accrued costs.

As of September 30, 2012 and 2011, we recorded $60 million and $173 million, respectively, of various liabilities related to the purchase of proved and unproved properties and other assets.

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

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

	Nine Months Ended September 30, 2012	2011
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$3,062	$3,065
Exchange of 0 and 3,000 shares of preferred stock for common stock	—	(3)
Balance, end of period	3,062	3,062
COMMON STOCK:		
Balance, beginning and end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,146	12,194
Stock-based compensation	116	120
Exchange of 0 and 3,000 shares of preferred stock for common stock	—	3
Purchase of contingent convertible notes	—	(123)
Reduction in tax benefit from stock-based compensation	(18)	(5)
Dividends on common stock	—	(48)
Dividends on preferred stock	—	(15)
Exercise of stock options	2	2
Balance, end of period	12,246	12,128
RETAINED EARNINGS:		
Balance, beginning of period	1,608	190
Net income (loss) attributable to Chesapeake	(1,069)	1,269
Dividends on common stock	(170)	(112)
Dividends on preferred stock	(128)	(113)
Balance, end of period	241	1,234
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(166)	(168)
Hedging activity	(15)	66
Investment activity	(7)	(4)
Balance, end of period	(188)	(106)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(33)	(24)
Purchase of 357,565 and 191,153 shares for company benefit plans	(9)	(5)
Release of 49,591 and 74,004 shares from company benefit plans	1	2
Balance, end of period	(41)	(27)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	15,327	16,298
NONCONTROLLING INTERESTS:		
Balance, beginning of period	1,337	—
Sales of noncontrolling interests	1,056	—
Net income attributable to noncontrolling interests	131	—
Distributions to noncontrolling interest owners	(160)	—
Balance, end of period	2,364	—
TOTAL EQUITY	$17,691	$16,298

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

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 and nine months ended September 30, 2012 (the "Current Quarter" and the "Current Period", respectively) and three and nine months ended September 30, 2011 (the "Prior Quarter" and the "Prior Period", respectively). Chesapeake's annual report on Form 10-K for the year ended December 31, 2011 (2011 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 and the Current Period are not necessarily indicative of the results to be expected for the full year.

Critical Accounting Policies

We consider accounting policies related to derivatives, variable interest entities, natural gas and oil properties and income taxes to be critical policies. These policies are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2011 Form 10-K.

Risks and Uncertainties

Our business strategy is to continue our reserves and production growth and transition our asset base from an exclusive focus on natural gas production to a focus that is, and in the future will remain, more balanced between natural gas and liquids production. This is a capital-intensive strategy, and we made capital expenditures in the Current Period that exceeded our cash flow from operations, filling this gap with borrowings and proceeds from sales of assets that we determined were non-core or did not fit our long-term plans. See Notes 8 and 16 for a description of our completed 2012 asset sales. We project that our capital expenditures will continue to exceed our operating cash flow through 2013; however, we expect to see a much smaller gap between our cash flow from operations and capital expenditures in 2013 than we have experienced in 2012.

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 earnings before interest, taxes, depreciation, depletion and amortization (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. Thus, the assets we select and schedule for sales, our budgeted capital expenditures and our natural gas, oil and NGL price forecasts are carefully considered as we project our future ability to comply with the financial covenant maintenance requirements of our corporate revolving bank credit facility. In September 2012, the existing leverage ratio covenant was increased through an amendment to the credit facility agreement. See Note 3 for discussion of the terms of the amendment. We would have been unable to meet the required ratio as of September 30, 2012 without this amendment primarily because the closing of asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. As a result, without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance. The amendment relaxes our required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. Failure to maintain compliance with the covenants of our revolving bank credit facility would, absent a waiver or amendment, allow lenders to declare an event of default and cause any outstanding indebtedness under the facility to become immediately due and payable. Such action could also lead to cross defaults under our senior note and contingent convertible senior note indentures. See Note 3 for further discussion of our debt instruments.

Based on ongoing reductions in our capital expenditures, expected commodity prices as reflected in futures prices and prices for our currently hedged production, our forecasted drilling and production, projected levels of indebtedness and certain asset sales presently being negotiated, we believe we will be in compliance with the financial maintenance covenants, including the amended leverage ratios, of our corporate revolving bank credit facility through 2013. 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. Our ability to generate operating cash flow and close asset sales in order to manage debt, however, are 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 is not completed in the anticipated time frame, or at all, or for less proceeds than anticipated, our ability to fund budgeted capital expenditures, reduce our indebtedness as planned and maintain our compliance with revolving bank credit facility covenants could be adversely affected.

We have a material exposure to natural gas prices, which reached 10-year lows in the Current Period. Approximately 70% and 83% of our estimated proved reserves volumes as of September 30, 2012 and December 31, 2011, respectively, were natural gas, and natural gas represented approximately 80% and 84% of our natural gas, oil and NGL sales volumes for the Current Period and the full year 2011, respectively. Although our natural gas derivative arrangements serve to mitigate a portion of the effect of price volatility on our cash flows, none of our 2013 natural gas production is currently protected by derivative instruments against downward price movement. Sustained low natural gas prices, and volatile natural gas, oil and NGL prices in general could have a material adverse effect on our financial position, results of operations and cash flows. In addition, lower natural gas, oil and NGL prices could result in a further reduction in the estimated quantity of proved reserves we report and in the estimated future net cash flows expected to be generated from our proved reserves.

In the Current Period, we reduced our estimate of proved reserves by 5.5 tcfe primarily due to the impact of downward natural gas price revisions. Natural gas prices used in estimating proved reserves decreased by 31% from $4.12 per mcf for the 12 months ended December 31, 2011 to $2.83 per mcf for the 12 months ended September 30, 2012 using 12-month average prices required by the SEC. The reserve reductions primarily involved the loss of significant proved undeveloped reserves, largely in the Barnett Shale and the Haynesville Shale plays, for which future development is uneconomic at the natural gas prices used in the reserves estimates. As a result of lower estimated reserves, as of September 30, 2012, we were required to impair the carrying value of our natural gas and oil properties and, if the trailing 12-month average natural gas prices are lower in subsequent periods, we could have additional impairments in the future. See Natural Gas and Oil Properties below for further discussion of our impairment of the carrying value of our natural gas and oil properties as of September 30, 2012. An impairment of this type is a non-cash charge that does not impact our liquidity or our ability to comply with financial covenants. 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.

Natural Gas and Oil Properties

On a quarterly basis, we analyze our unevaluated leasehold and transfer to evaluated properties leasehold that can be associated with reserves, leasehold that expired in the quarter or leasehold that is not a part of our development strategy and will be abandoned. As our strategic focus is shifting from a natural gas asset base to a more balanced natural gas and liquids asset base, and as our budgeted capital expenditures are being reduced in the Current Quarter, we identified undeveloped leasehold having a cost of $1.684 billion that would not be a part of our development strategy going forward. The acreage was primarily located in the Williston and DJ Basins, as well as other non-core leasehold located throughout our operating areas.

We also review, on a quarterly basis, the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In the Current Quarter, capitalized costs of natural gas and oil properties exceeded the estimated present value calculation of future net revenues from our proved reserves, net of related income tax considerations, resulting in an impairment in the carrying value of natural gas and oil properties of $3.315 billion. For the ceiling test calculation, costs used are those as of the end of the appropriate quarterly period. In calculating estimated future net revenues, current prices are calculated as the unweighted arithmetic average of natural gas and oil prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives designated as cash flow hedges. Cash flow hedges locked in prior to September 30, 2012 which relate to future production periods increased the ceiling test impairment by $279 million. As of September 30, 2012, none of our open derivative instruments were designated as cash flow hedges. Our natural gas and oil hedging activities are discussed in Note 7 of these condensed consolidated financial statements. See Risks and Uncertainties above for a discussion of the reduction in our estimated proved reserves in the Current Period and factors that could impact a future ceiling test impairment.

Held for Sale Assets and Liabilities

We are currently pursuing the sale of substantially all of our midstream business in order to narrow our strategic focus, and we expect to complete the sale in the 2012 fourth quarter. Substantially all of the associated assets and liabilities qualified as held for sale as of September 30, 2012 are 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 certain drilling rigs and land and buildings primarily in the Fort Worth, Texas area. The drilling rigs are reported under our oilfield services operating segment, and 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 oil and gas accounting. A summary of the assets and liabilities held for sale on our condensed consolidated balance sheet as of September 30, 2012 is detailed below.

	September 30, 2012 ($ in millions)
Cash	$14
Accounts receivable	90
Other assets	7
Current assets held for sale	$111
Natural gas gathering systems and treating plants, net of accumulated depreciation	$2,027
Oilfield services equipment, net of accumulated depreciation	24
Other property and equipment, net of accumulated depreciation and amortization	256
Property and equipment held for sale, net	$2,307
Investments	$123
Long-term assets held for sale	$123
Accounts payable	$33
Accrued liabilities	143
Current liabilities held for sale	$176
Asset retirement obligations	$2
Long-term liabilities held for sale	$2

Cash and Cash Equivalents and Restricted Cash

For purposes of the consolidated financial statements, Chesapeake considers investments in all highly liquid instruments with original maturities of three months or less at date of purchase to be cash equivalents. Restricted cash consists of balances required to be maintained by the terms of agreements governing the activities of CHK Utica, L.L.C. (CHK Utica) and CHK Cleveland Tonkawa, L.L.C. (CHK C-T). For CHK Utica, we must retain a minimum cash balance equal to two quarterly dividend payments. In addition, cash proceeds received from CHK Utica asset sales must be used to pay for CHK Utica's capital expenditures or to redeem its preferred shares. For CHK C-T, we must retain an amount of cash (remeasured quarterly) equal to (i) the next two quarters of preferred dividend payments plus (ii) the projected capital and operating expenditures for the next six months (net of its projected net revenues during such six-month period). See Note 6 for further discussion of these transactions.

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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 Current Period, the following shares of unvested restricted stock 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 September 30, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$21	56
5.75% cumulative convertible preferred stock (series A)	$16	39
5.00% cumulative convertible preferred stock (series 2005B)	$3	5
4.50% cumulative convertible preferred stock	$3	6
Unvested restricted stock	$—	3
Nine Months Ended September 30, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$64	56
5.75% cumulative convertible preferred stock (series A)	$47	39
5.00% cumulative convertible preferred stock (series 2005B)	$8	5
4.50% cumulative convertible preferred stock	$9	6
Unvested restricted stock	$—	4

As a result of the net loss to common stockholders in the Current Quarter and the Current Period, 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 the same in both periods: 644 million shares in the Current Quarter and 643 million shares in the Current Period. The basic and diluted loss per common share was $3.19 and $1.86 in the Current Quarter and the Current Period, respectively.

For the Prior Quarter and the Prior Period, all outstanding securities that were convertible into common stock were included in the calculation of diluted EPS. A reconciliation of basic EPS and diluted EPS for the Prior Quarter and the Prior Period is as follows:

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended September 30, 2011:			
Basic EPS	$879	638	$1.38
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	21	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	16	39	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	3	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	3	6	
Unvested restricted stock	—	8	
Outstanding stock options	—	1	
Diluted EPS	$922	753	$1.23
Nine Months Ended September 30, 2011:			
Basic EPS	$1,141	636	$1.79
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	64	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	47	39	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	8	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	9	6	
Unvested restricted stock	—	9	
Outstanding stock options	—	1	
Diluted EPS	$1,269	752	$1.69

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3. Debt

Our long-term debt consisted of the following as of September 30, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011
	($ in millions)	
Term loans due 2017[(a)]	$4,000	$—
7.625% senior notes due 2013[(b)]	464	464
9.5% senior notes due 2015	1,265	1,265
6.25% euro-denominated senior notes due 2017[(c)]	442	446
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018	474	474
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[(d)]	650	650
6.775% senior notes due 2019	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	1,785	1,719
Midstream revolving bank credit facility	—	1
Oilfield services revolving bank credit facility	336	29
Discount on senior notes and term loans[(f)]	(559)	(490)
Interest rate derivatives[(g)]	21	28
Total debt, net	16,218	10,626
Less current maturities of long-term debt, net[(b)]	(463)	—
Total long-term debt, net	$15,755	$10,626

(a) Subsequent to September 30, 2012, we used approximately $2.8 billion in proceeds from asset sales and $1.2 billion in partial proceeds from our new term loan (see Note 16) to fully repay the Term Loans due 2017.

(b) These senior notes are due in July 2013. There is $1 million of discount associated with these notes.

(c) The principal amount shown is based on the exchange rate of $1.2856 to €1.00 and $1.2973 to €1.00 as of September 30, 2012 and December 31, 2011, respectively. See Note 7 for information on our related foreign currency derivatives.

(d) 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.

(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 specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. In the third quarter of 2012, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the fourth quarter of 2012 under this provision. The notes are also convertible, at the holder's option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note's conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period in which contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$48.51	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	$107.27	June 14, 2019

(f) Discount as of September 30, 2012 and December 31, 2011 included $393 million and $444 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is based on an effective yield method. Also includes $114 million associated with our Term Loans due 2017 that were fully repaid subsequent to September 30, 2012.

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

Term Loans

In May 2012, we entered into $4.0 billion of unsecured term loans under a credit agreement that provided for term loans in an aggregate principal amount of $4.0 billion. The net proceeds of the term loans of approximately $3.789 billion after discount, customary fees and syndication costs were used to repay borrowings under our corporate revolving credit facility and for general corporate purposes. The term loans were issued at a discount of 3%, or $120 million, and the customary fees and syndication costs incurred were approximately $91 million. Subsequent to September 30, 2012, we used $4.0 billion in proceeds from asset sales and our new term loan (see Note 16) to fully repay the May 2012 term loans. We will record $155 million of associated losses with the repayment, including $86 million of deferred charges and $114 million of debt discount, offset by $45 million of interest accrued that will not be paid. Provisions that applied when the term loans were outstanding are described below.

Amounts borrowed under the term loan credit agreement bear interest, at our option, at either (a) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin (as described below) or (b) a base rate equal to the greater of (i) the prime rate quoted in the Wall Street Journal, (ii) the federal funds effective rate plus 0.50% per annum and (iii) 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. The Eurodollar rate is subject to a floor of 1.50% per annum and the base rate is subject to a floor of 2.50% per annum. Interest is payable quarterly or, if the Eurodollar rate applies, it may be payable at more frequent intervals. The initial applicable margin for Eurodollar loans is 7.0% per annum and the initial applicable margin for base rate loans is 6.0% per annum. If any amounts remain outstanding under the term loan credit agreement following January 1, 2013, the applicable margin under the term loan credit agreement will increase to 10.0% per annum for Eurodollar loans and to 9.0% per annum for base rate loans. Due to the escalating rate characteristic of the loan, we recognize interest expense using the interest method which, based on the current applicable interest rates, yields an 11.16% interest rate over the loan term. To the extent interest rates increase above the current applicable rates, the increase will be accounted for in the applicable period.

Amounts outstanding under the term loan credit agreement are unconditionally guaranteed on a joint and several basis by certain of the Company's direct and indirect wholly owned subsidiaries (including the subsidiaries that are subsidiary guarantors under our corporate revolving bank credit facility). The term loans are not secured by any assets of the Company or its subsidiaries.

The term loans, which rank equally in right of payment with our outstanding senior notes, mature on December 2, 2017 and may be repaid, in whole or in part, at any time in 2012 without premium or penalty. On and following January 1, 2013, we are required to pay a yield maintenance premium, equal to the present value of all interest payments that would have been made in respect of the principal of such loans from the date of such prepayment to maturity, in connection with any prepayment (including the prepayments described in the following paragraph) prior to December 2, 2017.

The 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 increase of dividends or payment of special dividends, investments in unrestricted subsidiaries and designations of subsidiaries as unrestricted subsidiaries. The term loan credit agreement also contains a covenant that requires that the net cash proceeds from certain asset dispositions and other asset sales, including assets of the Company or its subsidiaries in the Permian Basin in Texas and New Mexico, and certain financing transactions (both subject to certain thresholds and exceptions) be used to either (a) prepay loans outstanding under the term loan credit agreement or (b) reduce the commitments and repay amounts outstanding under our corporate revolving bank credit facility (or, to the extent the proceeds exceed the commitments under the revolving facility, other senior debt). If, prior to January 1, 2013, we use such designated proceeds to repay amounts outstanding under our corporate revolving bank credit facility, then the applicable margin under the term loan credit agreement will increase to 8.0% per annum for Eurodollar loans and 7.0% per annum for base rate loans. The term loan credit agreement does not contain financial maintenance covenants.

We were in compliance with all covenants under the term loan credit agreement at September 30, 2012. If we should fail to perform our obligations under the agreement, the term loans 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.

On and after May 11, 2013, the lenders will have the option (subject to certain thresholds) to exchange their loans under the term loan credit agreement for fixed rate notes (Exchange Notes). The Exchange Notes will bear interest at a fixed annual rate of 11.50%, payable semi-annually, will mature on December 2, 2017, will not be subject to any sinking fund or amortization and will contain substantially the same call protection (in the form of a customary treasury rate plus 50 basis points bond make-whole), covenants and events of default as the loans under the term loan credit agreement. The Exchange Notes will rank equally in right of payment with the loans under the term loan credit agreement.

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 wholly owned subsidiaries. Certain of our oilfield services subsidiaries, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain midstream and de minimis subsidiaries are not guarantors. See Note 14 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.

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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% and 8%, respectively.
During the Current Period, 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. At any time from and including November 15, 2012 to and including March 15, 2013, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest, if any, to the redemption date; provided that upon any redemption of the notes in part (and not in whole) pursuant to this redemption provision, at least $250 million aggregate principal amount of the notes remains outstanding.
During the Prior Period, we completed and settled tender offers to purchase the following senior notes and contingent convertible senior notes. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets. See Note 8 for further discussion of our Fayetteville Shale asset sale.

	Principal Amount Purchased ($ in millions)
7.625% senior notes due 2013	$36
9.5% senior notes due 2015	160
6.25% euro-denominated senior notes due 2017[a]	380
6.5% senior notes due 2017	440
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
Total senior notes	1,373
2.75% contingent convertible senior notes due 2035	55
2.5% contingent convertible senior notes due 2037	210
2.25% contingent convertible senior notes due 2038	266
Total contingent convertible senior notes	531
Total	$1,904

(a) We purchased €256 million in aggregate principal amount of our euro-denominated senior notes which had a value of $380 million based on the exchange rate of $1.4821 to €1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound cross currency swaps for the same principal amount. See Note 7 for additional information.

We paid $2.058 billion in cash for the tender offers described above and recorded associated losses of approximately $174 million. The losses included $154 million in cash premiums, $20 million of deferred charges, $160 million of note discounts and $2 million of interest rate hedging losses, offset by $162 million of the equity component of the contingent convertible notes.
During the Prior Period, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.
During the Prior Period, we purchased $140 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for approximately $128 million. Associated with these purchases, we recognized a

loss of $2 million.

In July 2013, the $464 million aggregate principal amount of our 7.625% senior notes will be due. No other scheduled principal payments are required on our senior notes until 2015.

COO Senior Notes

In October 2011, our wholly owned subsidiaries, Chesapeake Oilfield Operating, L.L.C. (COO) and Chesapeake Oilfield Finance, Inc. (COF), 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, 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 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 within 365 days after the closing of the COO senior notes offering 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 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. We also agreed to make additional interest payments to holders, up to a maximum of 1% per annum, of the COO senior notes if we do not comply with our obligations under the registration rights agreement. We did not file a registration statement within 365 days after the closing of the COO senior notes and in the Current Quarter accrued approximately $1 million of additional expense we expect to incur related to this delay.

Bank Credit Facilities

During the Current Period, we used three revolving bank credit facilities as sources of liquidity. In June 2012, we paid off and terminated our midstream credit facility. Our two 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 September 30, 2012	$1,785	$336
Letters of credit outstanding as of September 30, 2012	$31	$—

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

(b) Borrower is COO.

Our corporate and oilfield services 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 recent 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.

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 (a) December 31, 2013 and (b) 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	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 borrowings 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 September 30, 2012.

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 our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

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, but they are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes 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 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 at September 30, 2012. 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 midstream 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 anticipated sale 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 fully briefed as of August 21, 2012. Discovery in the case is proceeding. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against certain current and former directors and officers of the Company asserting breaches of fiduciary duties relating to alleged material omissions in the registration statement for the July 2008 offering. The derivative action is stayed pursuant to stipulation. On August 29, 2012, the plaintiff filed a motion to lift the stay, and on September 17, 2012, nominal defendant Chesapeake filed a cross-motion to stay the case pending resolution of the federal class action. 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 stipulated order, the individual defendants are not required to answer the complaint unless and until the plaintiff establishes standing to pursue claims derivatively.

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 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.

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 that was paid by Chesapeake. 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. Appellants' opening brief was filed on September 14, 2012, and Chesapeake filed its response on 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. 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. 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 to be filed in the federal securities class action described in the following paragraph.

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, a lead plaintiff was appointed, and on October 19, 2012, an amended complaint was filed against the Company, Mr. McClendon and certain other officers. The amended complaint asserts 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 seeks class certification, damages of an unspecified amount and attorneys' fees and other costs. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the case.

The Board of Directors is conducting an internal review of the financing arrangements between Mr. McClendon (and the entities through which he participates in the FWPP) and any third party that has had or may have a relationship with the Company in any capacity. 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 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, failing to disclose material information concerning such matters as Mr. McClendon’s participation in the FWPP and his related financing arrangements and the Company’s VPP transactions, engaging in activities that were in conflict with the best interest of the Plan, and permitting the Plan to over-concentrate in Chesapeake stock. The plaintiffs seek class certification, damages of an unspecified amount, equitable relief, and attorneys’ fees and other costs. On August 16, 2012, defendants were given 60 days following the date on which a consolidated amended complaint is filed to answer. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with these cases.

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. The Company and Mr. McClendon are providing information in response to the SEC’s inquiry. The Company has also received inquiries from other governmental and regulatory agencies and self-regulatory organizations concerning such matters and is responding to such inquiries.

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 October 11, 2012, the plaintiff appealed the dismissal to the Supreme Court of Oklahoma, and on October 15, 2012, the Supreme Court ordered the plaintiff to show cause why the appeal should not be dismissed as premature. On October 30, 2012, the plaintiff responded to the order to show cause.

Antitrust Investigations. On June 29, 2012, Chesapeake received a subpoena duces tecum 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 is providing information in response to these investigations, and its Board of Directors is conducting an internal review of the matter.

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. We have increased natural gas and oil properties by the full amount of a judgment entered in July 2012 against us in an action for specific performance of 2008 contracts to purchase natural gas and oil properties for $101 million in addition to recording prejudgment interest. The action was remanded following the reversal on appeal of the original trial court's holding that the contracts were not enforceable. Enforcement of the judgment has been stayed. On August 10, 2012, Chesapeake filed a motion for new trial and/or to alter or amend the judgment. The motion has been fully briefed.

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute incidental to the Company's business operations is likely to have a material adverse effect on its consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Environmental Risk

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 potential environmental liabilities that are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and assessing the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property.

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 matters. For four of the sites subject to EPA orders for compliance, CALLC also received and responded to a subpoena issued by the grand jury of the U.S. District Court for the Northern District of West Virginia. On September 28, 2012, an information alleging misdemeanor violations of the CWA by CALLC was filed in this federal district court, and on October 5, 2012, CALLC pled guilty, pursuant to a binding plea agreement with the U.S. Attorney for the Northern District of West Virginia, to three misdemeanor counts of unauthorized discharge of dredge or fill materials into a water of the U.S. In the plea agreement, CALLC has agreed to pay a fine of $200,000 for each misdemeanor, for a total fine of $600,000, and accept a two-year probationary term. Additionally, the parties have agreed that potential violations by CALLC at the three other sites subject to the aforementioned subpoena would be addressed in the ongoing civil proceeding. All terms of the plea agreement, including the proposed sentence, are subject to court approval.

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, and CALLC has agreed to pay a fine of $600,000 with respect to CWA criminal misdemeanor charges, 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 subsidiaries have sold 70 drilling rigs (net of 24 purchased rigs) 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 obligations 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 September 30, 2012, the minimum aggregate undiscounted future rig lease payments were approximately $332 million. During the Current Quarter, we repurchased 22 rigs from various lessors for an aggregate purchase price of $53 million, of which $25 million was deemed to be early lease termination costs and was recognized as Losses and Impairments of Fixed Assets and Other in the condensed consolidated statements of operations. See Note 11 for further discussion.

Chesapeake has contracts with various drilling contractors to utilize approximately 34 rigs with terms ranging from six months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2012, the aggregate undiscounted minimum future payments under these drilling rig commitments were approximately $316 million.

Compressor Leases

Through various transactions beginning in 2007, our compression subsidiary has sold 2,542 compressors (net of 11 purchased compressors), a significant portion of its compressor fleet, and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related 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 September 30, 2012, the minimum aggregate undiscounted future compressor lease payments were approximately $443 million. Subsequent to September 30, 2012, we repurchased 220 compressor units for approximately $28 million from various lessors, lowering our minimum aggregate undiscounted future compressor lease payments by approximately $23 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 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.

	September 30, 2012
	($ in millions)
2012	$282
2013	1,194
2014	1,535
2015	1,626
2016	1,683
2017 - 2099	11,235
Total	$17,555

Drilling Commitments

In December 2011, as part of our Utica joint venture development agreement with 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. Through September 30, 2012, we had spud 87 cumulative Utica wells and are therefore ahead of the drilling pace required to meet the cumulative drilling commitment by December 31, 2012. 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.

In conjunction with the acceleration in October 2011 of the remaining drilling carry owed to us by Total in our Barnett Shale joint venture, we agreed to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012. In January 2012, Chesapeake and Total agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and Total agreed to further reduce the minimum rig count from six to two rigs.

Property and Equipment Purchase Commitments

Much of the drilling equipment we purchase requires long production lead times. As a result, we have outstanding orders and commitments for such equipment. As of September 30, 2012, we had $197 million of purchase obligations related to future capital expenditures for drilling rigs and related equipment and hydraulic fracturing equipment in 2012 and 2013.

Natural Gas and Oil Purchase Commitments

We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners 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 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. We do not expect to meet the net acreage maintenance commitment with Total under the terms of our Barnett Shale joint venture agreement. We expect to have a net acreage shortfall of approximately 18,000 net acres, which, if not met by the December 31, 2012 measurement date, will result in a 2012 fourth quarter charge against earnings and a cash payment of approximately $36 million to Total in the first half of 2013.

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 fracing services continuously, we do not anticipate any material payments under this commitment. In addition, in September 2012, we agreed to purchase our pro-rata share, equal to approximately $105 million, of preferred equity securities offered by FTS to existing stockholders. We expect to complete this transaction in November 2012. 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.

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 over the price at the time of our original investment in July 2011, resulting in a conversion price of $15.80 per share. As of September 30, 2012, Clean Energy's common stock was trading at $13.17 per share. See Note 9 for further discussion of this investment.

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Longmont, Colorado. As of September 30, 2012, 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.P. (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 has 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. It is included in other current and non-current liabilities on our consolidated balance sheet as of September 30, 2012. We will release this liability over the two-year term of the guarantee if the assets are meeting the specific quarterly targets. No payment was required for the Current Period, and we recognized $2 million of gain associated with the release of the liability related to the quarterly targets achieved in the Current Period. To the extent we are required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings.

In conjunction with CMD’s investments in the newly formed entities Utica East Ohio Midstream, LLC, Cardinal Gas Services L.L.C., Ranch Westex JV, LLC and Glass Mountain Pipeline, LLC, as of September 30, 2012, CMD had committed to make capital contributions to these entities totaling approximately $1.1 billion through 2014. With the anticipated 2012 fourth quarter sale of substantially all of our midstream business, these commitments will become the responsibility of the acquirer of our midstream business. See Notes 9 and 10 for further discussion of these investments.

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

5. Other Long-Term Liabilities

Other long-term liabilities as of September 30, 2012 and December 31, 2011 are detailed below.

	September 30, 2012	December 31, 2011
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$279	$290
CHK C-T ORRI conveyance obligation[b]	167	—
Financing lease obligations[c]	143	143
Revenues and royalties due others	128	109
Mortgages payable[d]	56	56
Other	224	220
Total other long-term liabilities	$997	$818

(a) $17 million and $10 million of the total $296 million and $300 million obligations are recorded in other current liabilities as of September 30, 2012 and December 31, 2011, respectively. See Note 6 for further discussion of the transaction.

(b) $15 million of the total $182 million obligation is recorded in other current liabilities. See Note 6 for further discussion of the transaction.

(c) In 2009, we financed 113 real estate surface assets in the Barnett Shale area for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in 2010 and 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 has a floating rate of prime plus 275 basis points. At our option, we may prepay the term loan in full without penalty. The payment obligation is guaranteed by Chesapeake. As of September 30, 2012, our Barnett Shale headquarters building was classified as property and equipment held for sale on our condensed consolidated balance sheet.

6. Stockholders' Equity, Restricted Stock, Stock Options and Noncontrolling Interests

Common Stock

The following is a summary of the changes in our common shares issued for the Current Period and Prior Period:

	2012	2011
	(in thousands)	
Shares issued at January 1	660,888	655,251
Restricted stock issuances (net of forfeitures)	5,758	5,096
Stock option exercises	309	394
Preferred stock conversion	—	111
Shares issued at September 30	666,955	660,852

Preferred Stock

The following reflects our preferred shares outstanding for the Current Period and Prior Period:

	5.75%	5.75% (A)	4.5%	5.00% (2005B)
	(in thousands)			
Shares outstanding at January 1, 2012 and September 30, 2012	1,497	1,100	2,559	2,096
Shares outstanding at January 1, 2011	1,500	1,100	2,559	2,096
Conversion of preferred shares into common stock	(3)	—	—	—
Shares outstanding at September 30, 2011	1,497	1,100	2,559	2,096

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

Dividends

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

Dividends on our outstanding preferred stock are payable quarterly. We may pay dividends on our 5.00%% Cumulative Convertible Preferred Stock (Series 2005B) and our 4.50% Cumulative Convertible Preferred Stock in cash, common stock or a combination thereof, at our option. Dividends on both series of our 5.75% Cumulative Convertible Non-Voting Preferred Stock are payable only in cash.

Stock-Based Compensation

Chesapeake’s stock-based compensation program consists of restricted stock and, prior to 2006, stock options issued to employees and non-employee directors. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value of the equity instruments at the date of the grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisition, divestiture, 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, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	($ in millions)			
Natural gas and oil properties	$18	$30	$55	$90
General and administrative expenses	17	24	55	71
Natural gas, oil and NGL production expenses	6	8	18	26
Marketing, gathering and compression expenses	4	5	12	14
Oilfield services expenses	2	3	8	8
Total	$47	$70	$148	$209

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 changes in unvested shares of restricted stock for the Current Period is presented below.

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2012	19,544	$26.97
Granted	9,375	$21.16
Vested	(7,225)	$28.87
Forfeited	(1,165)	$24.90
Unvested shares as of September 30, 2012	20,529	$23.76

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $150 million based on the stock price at the time of vesting.

As of September 30, 2012, there was $356 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, the Prior Quarter, the Current Period and the Prior Period, we recognized reductions in tax benefits related to restricted stock of $14 million, $7 million, $19 million and $8 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

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

The following table provides information related to stock option activity for the Current Period:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in millions)
Outstanding at January 1, 2012	1,051	$9.84	1.41	$13
Exercised	(322)	$6.53		
Outstanding and exercisable at September 30, 2012	729	$11.31	0.96	$6

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

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

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

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 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 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 sheet. 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 capital and operating expenditures for the next six months (net of projected revenues during such six-month period). The amount so retained, approximately $112 million as of September 30, 2012, 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 will 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 are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of September 30, 2012, the redemption price and the liquidation preference were each $1,320 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 the Current Period, 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.

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% 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 net wells. 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 net wells 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.

As of September 30, 2012, $1.015 billion was recorded as noncontrolling interests on our condensed consolidated balance sheet representing the third-party investments in CHK C-T. For the Current Quarter and the Current Period, income of $19 million and $38 million, respectively, was attributable to the noncontrolling interests of CHK C-T. Under the development agreement, approximately 17 and 57 qualified net wells were added in the Current Quarter and Current Period, respectively.

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 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 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 September 30, 2012. 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 non-core Utica Shale assets in the Current Quarter, the amount reserved for paying capital expenditures, approximately $167 million, is reflected as restricted cash in other long-term assets on our condensed consolidated balance sheet as of September 30, 2012. See Note 8 for further discussion of the sale of non-core Utica Shale assets.

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 will 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 the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares are redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of September 30, 2012, the redemption price and the liquidation preference were each approximately $1,340 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.

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% 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 net wells. 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 net wells 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.

As of September 30, 2012 and December 31, 2011, $950 million was recorded as noncontrolling interests on our condensed consolidated balance sheets representing the third-party investments in CHK Utica. For the Current Quarter and the Current Period, income of approximately $22 million and $66 million, respectively, was attributable to the noncontrolling interests of CHK Utica. Under the development agreement, approximately 12 and 48 qualified net wells were added in the Current Quarter and Current Period, respectively.

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 (29,300 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 September 30, 2012, we had drilled or caused to be drilled 48 development wells, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $156 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 August 10, 2012, the Trust declared a cash distribution of approximately $27 million, or $0.61 per common unit and $0.48 per subordinated unit, for the three-month period ended June 30, 2012 and covering production for the period from March 1, 2012 to May 31, 2012. The distribution was paid on August 30, 2012 to record unitholders as of August 20, 2012. The distribution was subordinated, with $13 million paid to Chesapeake and $14 million paid to third-party unitholders.

We have determined that the Trust constitutes a variable interest entity (VIE) and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our condensed consolidated financial statements. As of September 30, 2012 and December 31, 2011, $365 million and $380 million, respectively, were recorded as noncontrolling interests on our condensed consolidated balance sheets representing the public unitholders' investment in common units of the Trust. For the Current Period, approximately $28 million of income was attributable to the Trust's noncontrolling interests in our condensed consolidated statement of operations. See Note 10 for further discussion of VIEs.

Cardinal Gas Services, L.L.C. Cardinal Gas Services, L.L.C. (Cardinal), an unrestricted, non-guarantor consolidated subsidiary, was formed in December 2011 to acquire, develop, operate and own midstream assets in the Utica Shale. In exchange for the contribution of approximately $14 million in midstream assets to Cardinal, we received 66% of the outstanding membership units of Cardinal. In exchange for approximately $5 million, Total E&P USA, Inc. (Total) received 25% of the outstanding membership units and in exchange for approximately $2 million, CGAS Properties, L.P. (CGAS), an affiliate of Enervest, Ltd., received 9% of the membership units. We have determined that Cardinal constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, Cardinal is included in our condensed consolidated financial statements. The contributions from Total and CGAS were recorded as noncontrolling interests. Each member is responsible for its proportionate share of capital costs. As of September 30, 2012 and December 31, 2011, the noncontrolling interest balances on the condensed consolidated balance sheets associated with the contributions from Total and CGAS were approximately $34 million and $7 million, respectively. For the Current Period, a nominal loss was attributable to Cardinal's noncontrolling interests in our condensed consolidated statement of operations.

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 the exposure to adverse market 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 hedged production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of September 30, 2012 and December 31, 2011, our natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Call Options: Chesapeake sells, 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. Chesapeake also buys put swaptions, that are exercisable on a specific date, which allows us to enter into a swap at a fixed price for a certain period of time.
- Knockout Swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than a certain pre-determined knockout price.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. Our 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.

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, oil and NGL derivative instruments as of September 30, 2012 and December 31, 2011 are provided below.

	September 30, 2012		December 31, 2011	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	204	$(58)	—	$—
Call options	492	(250)	1,357	(284)
Basis protection swaps	119	(17)	106	(42)
Put swaptions	11	(1)	—	—
Total natural gas	826	(326)	1,463	(326)
Oil (mmbbl):				
Fixed-price swaps	33.3	97	14.9	15
Call options	74.2	(785)	94.7	(1,282)
Call swaptions	8.0	(20)	7.8	(53)
Fixed-price knockout swaps	—	—	0.8	7
Total oil	115.5	(708)	118.2	(1,313)
Total estimated fair value		$(1,034)		$(1,639)

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following this guidance, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is 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. We have currently elected not to designate any of our natural gas and oil derivatives as cash flow hedges. Therefore, changes in the fair value of these derivatives for the Current Period are reported in the condensed consolidated statement of operations.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
		($ in millions)		
Natural gas, oil and NGL sales	$1,464	$1,427	$3,798	$3,892
Gains (losses) on natural gas, oil and NGL derivatives	(27)	980	824	783
Gains (losses) on ineffectiveness of cash flow hedges	—	(5)	—	13
Total natural gas, oil and NGL sales	$1,437	$2,402	$4,622	$4,688

Hedging Facility

We have a multi-counterparty secured hedging facility with 18 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.5 billion under the terms of the facility. As of September 30, 2012, we had hedged under the facility 1.4 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 and sale/leaseback arrangements. 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 September 30, 2012 and December 31, 2011, our interest rate derivative instruments consisted of the following types of instruments:

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

The notional amount and the estimated fair value of our interest rate derivatives outstanding as of September 30, 2012 and December 31, 2011 are provided below.

	September 30, 2012		December 31, 2011	
	Notional Amount	Fair Value	Notional Amount	Fair Value
		($ in millions)		
Interest rate:				
Swaps	$1,050	$(39)	$1,050	$(42)
Swaptions	500	(2)	300	—
Totals	$1,550	$(41)	$1,350	$(42)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
		($ in millions)		
Interest expense on senior notes	$187	$152	$546	$494
Interest expense on credit facilities	13	18	51	49
Interest expense on term loans	112	—	173	—
(Gains) losses on interest rate derivatives	(2)	—	(4)	19
Amortization of loan discount and other	24	8	67	30
Capitalized interest	(298)	(174)	(770)	(555)
Total interest expense	$36	$4	$63	$37

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 $21 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. As a result, we reclassified a loss of $38 million from accumulated other comprehensive income to the condensed consolidated statement of operations, $20 million of which related to the unwound notional amount and was included in losses on purchases or exchanges of debt, and $18 million of which related to future interest associated with the unwound principal and was included in interest expense. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay Chesapeake €11 million and Chesapeake pays the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake €344 million and Chesapeake will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of $1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in Chesapeake's expected cash flows related to changes in foreign exchange rates and therefore the swaps qualify as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $37 million at September 30, 2012. The euro-denominated debt in long-term debt has been adjusted to $442 million at September 30, 2012 using an exchange rate of $1.2856 to €1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

In accordance with accounting guidance for derivatives and hedging, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets. Derivative instruments reflected as current in the condensed consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. The derivative settlement amounts are not due until the month in which the related 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.

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The following table presents the fair value and location of each classification of derivative instrument disclosed in the condensed consolidated balance sheets as of September 30, 2012 and December 31, 2011 on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value September 30, 2012	December 31, 2011
		($ in millions)	
Asset Derivatives:			
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$108	$54
Commodity contracts	Long-term derivative instruments	36	1
Total		144	55
Liability Derivatives:			
Designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	(37)	(38)
Total		(37)	(38)
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(225)	(232)
Commodity contracts	Long-term derivative instruments	(953)	(1,462)
Interest rate contracts	Short-term derivative instruments	(2)	—
Interest rate contracts	Long-term derivative instruments	(39)	(42)
Total		(1,219)	(1,736)
Total derivative instruments		$(1,112)	$(1,719)

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

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

		Three Months Ended September 30,		Nine Months Ended September 30,	
Fair Value Derivatives	Location of Gain (Loss)	2012	2011	2012	2011
			($ in millions)		
Interest rate contracts	Interest expense	$2	$3	$6	$14

We include the expense on the hedged item (i.e., fixed-rate borrowings) in the same line item – interest expense – as the offsetting gain or loss on the related interest rate swap listed above. For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, this expense was $0, $2 million, $0 and $23 million respectively.

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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 September 30,			
	2012		2011	
	Before Tax	After Tax	Before Tax	After Tax
		($ in millions)		
Balance, beginning of period	$(306)	$(190)	$(177)	$(110)
Net change in fair value	4	3	121	75
Gains reclassified to income	(9)	(6)	(129)	(80)
Balance, end of period	$(311)	$(193)	$(185)	$(115)

	Nine Months Ended September 30,			
	2012		2011	
	Before Tax	After Tax	Before Tax	After Tax
		($ in millions)		
Balance, beginning of period	$(287)	$(178)	$(291)	$(181)
Net change in fair value	4	3	338	210
Gains reclassified to income	(28)	(18)	(232)	(144)
Balance, end of period	$(311)	$(193)	$(185)	$(115)

Approximately $179 million of the $193 million of accumulated other comprehensive loss as of September 30, 2012 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges. Because the originally forecasted transactions are still expected to occur, these amounts are being recognized in earnings in the month the originally forecasted production occurs. As of September 30, 2012, we expect to transfer approximately $13 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 September 30, 2012, none of our open derivative instruments were designated as cash flow hedges.

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

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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
		($ in millions)			
Gain (Loss) Recognized in AOCI (Effective Portion):					
Commodity contracts	AOCI	$—	$122	$—	$372
Foreign currency contracts	AOCI	4	(1)	4	(34)
		$4	$121	$4	$338
Gain (Loss) Reclassified from AOCI (Effective Portion):					
Commodity contracts	Natural gas, oil and NGL sales	$9	$129	$28	$270
Foreign currency contracts	Interest expense	—	—	—	(18)
Foreign currency contracts	Loss on purchase of debt	—	—	—	(20)
		$9	$129	$28	$232
Gain (Loss) Recognized in Income Commodity contracts:					
Ineffective portion	Natural gas, oil and NGL sales	$—	$(5)	$—	$13
Amount initially excluded from effectiveness testing	Natural gas, oil and NGL sales	—	—	—	22
		$—	$(5)	$—	$35

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 derivatives:

Derivative Contracts	Location of Gain (Loss)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
		($ in millions)			
Commodity contracts	Natural gas, oil and NGL sales	$(36)	$851	$796	$491
Interest rate contracts	Interest expense	—	(3)	(2)	(14)
Total		$(36)	$848	$794	$477

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with 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. On September 30, 2012, our natural gas, oil, NGL and interest rate derivative instruments were spread among 16 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 the majority of our natural gas, oil, and NGL derivatives.

8. Acquisitions and Divestitures

Acquisition of Bronco Drilling

In June 2011, we acquired Bronco Drilling Company, Inc., a publicly traded contract land drilling services company, for an aggregate purchase price of approximately $339 million, or $11.00 per share of Bronco common stock. The acquisition was accounted for as a business combination which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. Pro forma financial information is not presented as it would not be materially different from the information presented in the consolidated statement of operations.

Asset Sales

During the Current Period and the Prior Period, we engaged in the asset sales transactions described below as well as other individually insignificant sales.

Permian Basin. In September 2012, we sold our producing assets in the Midland Basin portion of the Permian Basin to affiliates of Houston-based EnerVest, Ltd. for approximately $376 million in cash. The properties included approximately 35 mmcfe per day of current net production.

Non-Core Utica Shale. In August 2012, we sold approximately 72,000 net acres of non-core leasehold in the Utica shale play in Ohio to affiliates of EnerVest for approximately $358 million in cash.

Texoma Woodford. In April 2012, we sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Bryan, Carter, Johnston and Marshall counties in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash. The properties included approximately 25 mmcfe per day of current net production.

Fayetteville Shale. In March 2011, we sold all of our Fayetteville Shale assets in central Arkansas to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP; ASX:BHP), for net proceeds of approximately $4.65 billion in cash. The properties sold consisted of approximately 487,000 net acres of leasehold, net production at closing of approximately 415 million cubic feet of natural gas equivalent per day and midstream assets consisting of approximately 420 miles of pipeline. Of the total proceeds received, $350 million was allocated to our Fayetteville Shale midstream assets and a $7 million gain was recorded on the divestiture of those assets. The remainder of the proceeds was allocated to our Fayetteville Shale natural gas and oil properties.

Under full cost accounting rules, we account for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss. In conjunction with each of these transactions, affiliates of our 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.

Joint Ventures

As of September 30, 2012, 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 for future drilling and completion cost sharing totaling $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. The carry obligations paid by a joint venture partner are for a specified percentage of our drilling and completion cost obligations. 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	$2,032	$1,249
Niobrara	CNOOC	February 2011	33.3%	570	697	1,267	495
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080	2,200	—
Barnett	TOT	January 2010	25.0%	800	1,404 (c)	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 (d)	3,158	—
				$7,100	$9,036	$16,136	$1,744

(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 September 30, 2012. The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. 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. See Note 4 for further discussion of the Utica drilling carries.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of drilling carry obligation billed and $425 million for the remaining drilling carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and TOT agreed to further reduce the minimum rig count from six to two rigs.

(d) In September 2009, PXP accelerated the payment of its remaining drilling carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $655 million and $1.868 billion, respectively, in drilling and completion carries paid by our joint venture partners, CNOOC, TOT and STO.

During the Current Period, as part of our joint venture agreements with TOT and STO, we sold interests in additional leasehold we acquired in the Marcellus, Barnett and Utica shale plays to our joint venture partners for approximately $228 million. In the Prior Period, as part of our joint venture agreements with CNOOC, TOT, STO and PXP, we sold interests in additional leasehold in the Eagle Ford, Barnett, Marcellus and Haynesville and Bossier shale plays to our joint venture partners for approximately $474 million.

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. We retain drilling rights on the properties below currently producing intervals and outside of producing well bores.

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 and the expenses that will apply in the future will depend on the actual production expenses and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs.

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 VPPs consist of the following:

Date of VPP	Division	Proceeds	Proved Reserves (at time of sale)	$ / mcfe	Original Term
		($ in millions)	(bcfe)		(years)
March 2012	Anadarko Basin Granite Wash	$744	160	$4.68	10
May 2011	Mid-Continent	853	177	$4.82	10
September 2010	Barnett Shale	1,150	390	$2.93	5
February 2010	East Texas and Texas Gulf Coast	180	46	$3.95	10
August 2009	South Texas	370	68	$5.46	8
December 2008	Anadarko and Arkoma Basins	412	98	$4.19	8
August 2008	Anadarko Basin	600	93	$6.38	11
May 2008	Texas, Oklahoma and Kansas	622	94	$6.53	11
December 2007	Kentucky and West Virginia	1,100	208	$5.29	15
		$6,031	1,334	$4.52	

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

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, originally entered into in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets, including Enervest as described above. See Note 16 for further discussion of our Permian Basin asset sales subsequent to September 30, 2012.

9. Investments

At September 30, 2012 and December 31, 2011, we had the following investments:

	Approximate Ownership %	Accounting Method	Carrying Value September 30, 2012	December 31, 2011
			($ in millions)	
Chesapeake Midstream Partners, L.P.	—	Equity	$—	$987
FTS International, Inc.	30%	Equity	201	235
Chaparral Energy, Inc.	20%	Equity	144	143
Sundrop Fuels, Inc.	50%	Equity	112	34
Clean Energy Fuels Corp.	—	Cost	100	50
Twin Eagle Resource Management, LLC	30%	Equity	30	20
Clean Energy Fuels Corp.	1%	Fair Value	13	12
Gastar Exploration Ltd.	10%	Fair Value	11	22
Other	—	—	36	28
Total investments			$647	$1,531

Chesapeake Midstream Partners, L.P. In June 2012, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners for cash proceeds of $2.0 billion. We recorded a $1.032 billion gain associated with the transaction, including the recognition of a $13 million deferred gain related to equipment previously sold to ACMP.

During the Current Period, we recorded positive equity method adjustments of $46 million for our share of ACMP's income, received cash distributions of $56 million from ACMP and recorded accretion adjustments of $4 million related to our share of equity in excess of cost. See Note 10 for further discussion of ACMP.

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company which, through its subsidiaries, provides pressure pumping and well stimulation to oil and gas companies.

In the Current Period, we recorded negative equity method adjustments, prior to intercompany profit eliminations, of $71 million for our share of FTS's net loss and recorded accretion adjustments of $34 million related to the excess of our underlying equity in net assets of FTS over our carrying value. We also funded a capital call of $3 million in the Current Period. The carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $633 million as of September 30, 2012, of which $296 million was attributed to goodwill. The value attributed to goodwill decreased by $200 million during the Current Quarter, 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 addition, in September 2012, we agreed to purchase our pro-rata share, equal to approximately $105 million, of preferred equity securities offered by FTS to existing stockholders. We expect to complete this transaction in November 2012. 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 Period, we recorded a positive equity method adjustment of $5 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 $2 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 $52 million

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as of September 30, 2012. 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 will fund construction of a nonfood biomass-based “green gasoline” plant, capable of annually producing more than 40 million gallons of gasoline from natural gas and waste cellulosic material. The investment is intended to accelerate the development of an affordable, stable, room-temperature, natural gas-based fuel for immediate use in automobiles, diesel engine vehicles and aircraft. As of September 30, 2012, we had funded $115 million of our commitment, of which $80 million was in the Current Period. 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. The full investment will represent approximately 50% of Sundrop Fuels’ equity on a fully diluted basis.

In the Current Period, we recorded a $2 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 September 30, 2012. 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 will use our $150 million investment to accelerate its build-out of LNG fueling infrastructure for heavy-duty trucks at truck stops across interstate highways in the U.S.

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. During the Current Period, the carrying value of our investment increased as the common stock price of Clean Energy increased from $12.46 per share as of December 31, 2011 to $13.17 per share as of September 30, 2012. Through September 30, 2012, we had recorded a mark-to-market 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. In the Current Period, we invested an additional $16 million. During the Current Period, we recorded a $6 million charge related to our share of Twin Eagle’s net loss.

Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE Amex:GST), based in Houston, Texas, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. Our investment in Gastar has a cost basis of $89 million and is classified as available for sale, and reported at fair value. During the Current Period, the carrying value of our investment decreased as the common stock price of Gastar decreased from $3.18 per share as of December 31, 2011 to $1.66 per share as of September 30, 2012. In March 2009, we booked an other-than-temporary-impairment of $70 million, and, through September 30, 2012, we had recorded a mark-to-market loss of $8 million in accumulated other comprehensive income for this investment.

Investments Held for Sale

Pursuant to our reclassification of certain assets and liabilities to held for sale, the following investments held by our midstream business have been identified as investments held for sale.

	Approximate Ownership %	Accounting Method	Carrying Value	
			September 30, 2012	December 31, 2011
			($ in millions)	
Utica East Ohio Midstream, LLC	59%	Equity	$75	$—
Ranch Westex JV, LLC	33%	Equity	32	—
Glass Mountain Pipeline, LLC	25%	Equity	16	—
Total investments held for sale			$123	$—

Utica East Ohio Midstream, LLC. In March 2012, CMD entered into an agreement to form Utica East Ohio Midstream, LLC (UEOM) with M3 Midstream, L.L.C. and EV Energy Partners, L.P. to develop necessary infrastructure for the gathering and processing of natural gas and NGL in the Utica Shale play in eastern Ohio. The infrastructure complex will consist of natural gas gathering and compression facilities constructed and operated by CMD, as well as processing, NGL fractionation, loading and terminal facilities constructed and operated by M3 Midstream, L.L.C. CMD's total commitment is $474 million in exchange for an ownership of approximately 59% in UEOM. UEOM is not consolidated because we do not have a controlling interest. As of September 30, 2012, we had funded $75 million of CMD’s total commitment. See Note 10 for further discussion of UEOM.

Ranch Westex, JV LLC. In December 2011, CMD entered into an agreement to form Ranch Westex JV, LLC with two other parties to develop, construct and operate necessary infrastructure for the processing and gathering of natural gas in Ward County, Texas. CMD’s total commitment is $36 million. As of September 30, 2012, we had funded $33 million of this commitment.

Glass Mountain Pipeline, LLC. In April 2012, CMD entered into an agreement with two other parties to form Glass Mountain Pipeline, LLC to construct a 210 mile pipeline in western and north central Oklahoma in which CMD had a 50% ownership. In September 2012, CMD sold 50% of that interest for $47 million and recorded a gain of $31 million. In October 2012, we sold our remaining interest for $52 million and will record an additional gain of $31 million in the fourth quarter of 2012. See Note 10 for further discussion of Glass Mountain Pipeline, LLC.

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 VIEs

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 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 September 30, 2012, approximately $445 million of net natural gas and oil properties, $20 million of current liabilities, $1 million of cash and cash equivalents, $5 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.

Cardinal Gas Services, L.L.C. We own an approximate 66% interest in Cardinal, a consolidated unrestricted non-guarantor midstream subsidiary (see Note 6 under Noncontrolling Interests for further discussion). Cardinal is considered a VIE because its total equity at risk, as of September 30, 2012, is not sufficient to permit it to finance its activities without additional subordinated financial support. It is expected that we, along with the other equity partners, will make regular capital contributions to Cardinal for our proportionate share of its capital costs. This VIE is consolidated since we have a controlling interest in the VIE through voting rights. In consolidation, as of September 30, 2012, approximately $14 million of current assets, $121 million of net natural gas gathering systems and treating plants and $31 million of current liabilities were attributable to Cardinal, which we have presented parenthetically on the face of the condensed consolidated balance sheets as held for sale.

Unconsolidated VIEs

Chesapeake Midstream Partners, L.P. In two transactions completed on June 15 and June 29, 2012, we sold our limited partner and general partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP). Prior to these sales, we had an approximate 46% interest in ACMP through our ownership of common and subordinated limited partner units and general partner interest (see Note 9 for further details). ACMP focuses on unregulated business activities in service to both Chesapeake and third-party natural gas producers and its revenues are generated from gathering, compression, dehydration and treating services. Certain Chesapeake employees have provided services to ACMP through an employee secondment agreement, and ACMP has utilized various support functions within Chesapeake, including accounting, human resources and information technology in return for certain cost reimbursements. We have agreed to provide certain transition services to ACMP following the sale of our ACMP interests, including the continuation of general and administrative services until December 31, 2013 and the secondment, pending any transfer, of certain personnel that perform services for ACMP until December 31, 2012, which date may be extended to March 31, 2013.

ACMP is considered a VIE because of the significance of its operations to us and the contractual arrangements between Chesapeake and ACMP that pass certain economic risks to us which are disproportionate to our economic interest. These primarily include certain gas gathering agreements with ACMP pursuant to which we have committed to deliver annually specified minimum volumes of natural gas under firm transportation agreements, and an EBITDA guarantee CMD issued to ACMP in conjunction with our December 2011 sale of Appalachia Midstream Services, L.L.C. (AMS). Our rights and commitments under our contractual arrangements with ACMP constitute variable interests. See Other Commitments in Note 4.

Our risk of loss related to ACMP includes certain commitments to ACMP through the EBITDA guarantee and under our firm transportation agreements that could require us to make shortfall payments in the event we do not meet our minimum volume commitments or ACMP does not meet specific EBITDA targets. The creditors or beneficial holders of ACMP common units have no recourse to the general credit of Chesapeake. This VIE remains unconsolidated since

the power to direct the activities which are most significant to ACMP's economic performance are with the general partner. Prior to June 29, 2012, we used the equity method to account for this investment.
Utica East Ohio Midstream, LLC. We have an approximate 59% interest in Utica East Ohio Midstream, LLC (UEOM), an unconsolidated non-guarantor entity which we formed with M3 Midstream L.L.C. and EV Energy Partners, L.P. to develop necessary infrastructures for gathering and processing of natural gas and NGL in the Utica shale play in eastern Ohio (see Note 9 for further details). UEOM is considered a VIE because its total equity at risk, as of September 30, 2012, is not sufficient to permit it to finance its activities without additional subordinated financial support. It is expected that we, along with the other equity partners, will make regular capital contributions to UEOM for our

proportionate share of its capital costs. This VIE remains unconsolidated since the power to direct the activities which are most significant to UEOM's economic performance is shared between us and the other equity holders. We are using the equity method to account for this investment. As of September 30, 2012 , this investment was classified as held for sale.

Mineral Acquisition Company I, L.P. In the Current Period, 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 will 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.

Glass Mountain Pipeline, LLC. As of September 30, 2012, we had a 25% interest in Glass Mountain Pipeline, LLC (GMP), an unconsolidated entity which we formed with Gavilon Energy Holdings II, LLC and Glass Mountain Holding, LLC to construct a 210 mile crude oil pipeline in Oklahoma (see Note 9 for further details). GMP entered into separate agreements with our wholly owned subsidiary, Chesapeake Energy Marketing, Inc., for throughput and deficiency commitments. GMP is considered a VIE because its total equity at risk, as of September 30, 2012, is not sufficient to permit it to finance its activities without additional subordinated financial support. It is expected that all the equity partners will make regular capital contributions to GMP for their proportionate share of capital costs. This VIE remains unconsolidated since the power to direct the activities that are most significant to GMP's economic performance is shared among the three equity holders.

11. Losses on Sales and Impairment 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 and the Current Period, we determined that certain of our property, plant and equipment were being carried at values that were not recoverable and in excess of fair value. As a result, we recognized the impairments described below.

Land and Buildings. In the Current Quarter and Current Period, we recognized $7 million and $227 million of impairment losses, respectively, associated with an office building and surface land located in our Barnett Shale operating area. Due to depressed natural gas prices during 2012 and a shift to a more liquids-focused drilling program, we have significantly reduced our Barnett Shale operations. The change in business climate related to the Barnett Shale required us to test these long-lived assets for recoverability in the Current Period. We received a purchase offer from a third party that we used to determine the fair value of the office building and measured the fair value of the surface land using prices from orderly sales transactions for comparable properties between market participants. The office building and surface land are included in our other operating segment.

Drilling Rigs and Equipment. As our strategic focus is shifting from a natural gas asset base to a more balanced natural gas and liquids asset base, and as our budgeted capital expenditures are being reduced, our active rig count has decreased significantly with a corresponding increase in the number of idle rigs we own or lease. In the Current Quarter, we negotiated the purchase of 22 rigs previously sold in our sale leaseback transactions described in Note 4 from various lessors for an aggregate purchase price of $53 million, of which $25 million was deemed to be early lease termination costs and was recognized as Losses and Impairments of Fixed Assets and Other in the condensed consolidated statements of operations.

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In the Current Quarter, we sold nine drilling rigs at auction for net proceeds of $4 million and recognized a $10 million loss on those sales.

In the Current Quarter and Current Period, we recognized $6 million and $20 million, respectively, of impairment losses on certain of our owned drilling rigs due to the expectation that these particular drilling rigs would have insufficient cash flow to recover their carrying values in the business climate due to depressed natural gas prices. We estimated the fair value of the drilling rigs using prices that would be received to sell each rig in an orderly transaction between market participants. In the Current Period, we also recognized $9 million of impairment losses primarily related to drill pipe and other equipment. The drilling rigs and equipment are included in our oilfield services operating segment.

12. 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 Gastar Exploration Ltd. (NYSE Amex: GST) and Clean Energy Fuels Corporation (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 company common stock.

Derivatives. The fair value 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. Derivatives are also subject to the risk that either party to the contract will be unable to meet their obligations. We factor non-performance risk into the valuation of our derivatives using current published credit default swap rates. To date, this has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of related designated fair value interest rate swaps. We currently do not have any debt recorded at fair value since we have no open fair value hedges.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of September 30, 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	$6	$—	$—	$6
Investments	24	—	—	24
Other long-term assets	87	—	—	87
Other long-term liabilities	(83)	—	—	(83)
Derivatives:				
Commodity assets	—	112	32	144
Commodity liabilities	—	(73)	(1,105)	(1,178)
Interest rate liabilities	—	(39)	(2)	(41)
Foreign currency liabilities	—	(37)	—	(37)
Total derivatives	—	(37)	(1,075)	(1,112)
Total	$34	$(37)	$(1,075)	$(1,078)

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

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Investments	$34	$—	$—	$34
Other long-term assets	61	—	—	61
Other long-term liabilities	(62)	—	—	(62)
Derivatives:				
Commodity assets	—	46	9	55
Commodity liabilities	—	(31)	(1,663)	(1,694)
Interest rate liabilities	—	(42)	—	(42)
Foreign currency liabilities	—	(38)	—	(38)
Total derivatives	—	(65)	(1,654)	(1,719)
Total	$33	$(65)	$(1,654)	$(1,686)

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

	Derivatives			
	Commodity	Interest Rate	Foreign Currency	Debt
	($ in millions)			
Beginning Balance as of January 1, 2012	$(1,654)	$—	$—	$—
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]	525	4	—	—
Total purchases, issuances, sales and settlements:				
Sales	—	(6)	—	—
Settlements	56	—	—	—
Ending Balance as of September 30, 2012	$(1,073)	$(2)	$—	$—
Beginning Balance as of January 1, 2011	$(1,954)	$(69)	$(43)	$(1,371)
Total gains (losses) (realized/unrealized):				
Included in earnings[(a)]	256	21	—	—
Total purchases, issuances, sales and settlements:				
Sales	—	(6)	—	—
Settlements	146	—	—	—
Transfers in and out of Level 3[(b)]	—	54	43	1,371
Ending Balance as of September 30, 2011	$(1,552)	$—	$—	$—

(a)	Natural Gas, Oil and NGL Sales		Interest Expense	
	2012	2011	2012	2011
	($ in millions)			
Total gains (losses) included in earnings for the period	$525	$256	$4	$21
Change in unrealized gains (losses) relating to assets still held at reporting date	$370	$133	$(2)	$—

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

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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, oil and NGL, unpublished forward interest rate curves, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts, e.g. an increase (decrease) in the forward prices and volatility of natural gas, oil and NGL prices will decrease (increase) the fair value of natural gas, oil and NGL derivatives; an increase (decrease) in forward rates and volatility of interest rates will decrease (increase) the fair value of interest rate 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 September 30, 2012	
					($ in millions)	
Oil Trades[a]	Oil price volatility curve	14.79% - 32.61%	22.44	%	$(805	)
Natural Gas Trades[a]	Natural gas price volatility curve	21.61% - 41.21%	23.51	%	$(251	)
Natural Gas Basis Swaps[b]	Physical pricing point forward curves	($1.87) - $0.05	$(0.21	)	$(17	)
Interest Rate Swaptions:[a]	Forward interest rate curve	0.30% - 2.94%	1.46	%	$(2	)
	Interest rate volatility	43.14% - 43.35%	43.25	%		

(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 non-recurring basis, to determine impairments. These assets consist primarily of land, a building, drilling rigs and drill pipe. 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. See Note 11 for additional discussion.
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.

	September 30, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		($ in millions)		
Short-term debt (Level 1)	$463	$481	$—	$—
Long-term debt (Level 1)	$9,727	$10,299	$8,849	$9,709
Long-term debt (Level 2)	$6,007	$5,801	$1,749	$1,690

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13. 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.

COO, a wholly owned subsidiary of COS, is a diversified oilfield services company that we formed in October 2011 to own and operate our oilfield service assets. COO provides a wide range of well site services, primarily to Chesapeake and its working interest partners, including contract drilling, hydraulic fracturing, oilfield rentals, transportation and manufacturing of natural gas compressor packages and related production equipment. In connection with the reorganization of our oilfield services subsidiaries and operations, those subsidiaries were released from the guarantees and other credit support obligations that existed for the benefit of Chesapeake and its other subsidiaries, including Chesapeake’s senior notes and contingent convertible senior notes, its corporate revolving bank credit facility and its multi-counterparty hedging facility. In addition, COO and its subsidiaries entered into agreements with Chesapeake pursuant to which they sublease rigs, provide certain oilfield services and obtain certain administrative services.

As a result of the formal reorganization of our oilfield services business in October 2011, we are recognizing our oilfield services business as a reportable segment. Historically, our oilfield services business was presented as part of other operations. All prior year information has been restated to reflect the addition of our oilfield services business as a new reportable segment.

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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 $1.541 billion, $1.324 billion, $3.877 billion and $3.739 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. The following table presents selected financial information for Chesapeake's operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other Operations	Intercompany Eliminations	Consolidated Total
	($ in millions)					
For the Three Months Ended September 30, 2012:						
Revenues	$1,437	$2,922	$482	$—	$(1,871)	$2,970
Intersegment revenues	—	(1,541)	(330)	—	1,871	—
Total revenues	$1,437	$1,381	$152	$—	$—	$2,970
Income (loss) before income taxes	$(3,073)	$120	$(2)	$(152)	$(124)	$(3,231)
For the Three Months Ended September 30, 2011:						
Revenues	$2,402	$2,746	$343	$—	$(1,514)	$3,977
Intersegment revenues	—	(1,324)	(190)	—	1,514	—
Total revenues	$2,402	$1,422	$153	$—	$—	$3,977
Income (loss) before income taxes	$1,552	$78	$27	$(56)	$(90)	$1,511
For the Nine Months Ended September 30, 2012:						
Revenues	$4,622	$7,587	$1,434	$—	$(4,865)	$8,778
Intersegment revenues	—	(3,877)	(988)	—	4,865	—
Total revenues	$4,622	$3,710	$446	$—	$—	$8,778
Income (loss) before income taxes	$(1,896)	$1,279	$96	$(654)	$(362)	$(1,537)
For the Nine Months Ended September 30, 2011:						
Revenues	$4,688	$7,583	$866	$—	$(4,229)	$8,908
Intersegment revenues	—	(3,739)	(490)	—	4,229	—
Total revenues	$4,688	$3,844	$376	$—	$—	$8,908
	$2,138	$239	$72	$(131)	$(237)	$2,081

Income (loss) before income taxes						
As of September 30, 2012:						
Total Assets	$39,485	$3,951	$2,067	$2,476	$(2,308	) $45,671
As of December 31, 2011:						
Total Assets	$35,403	$4,047	$1,571	$2,718	$(1,904	) $41,835

14. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets, and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 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 are not guarantors of our senior notes, contingent convertible senior notes or corporate credit facility but are subject to the covenants and guarantees in their revolving bank credit facility agreement referred to in Note 3 that limit their ability to pay dividends or distributions or make loans to Chesapeake. COS and its subsidiaries were released as guarantors of our senior notes and corporate credit facility in October 2011 when they were formally reorganized and capitalized. Our midstream subsidiary, CMD, and its certain of its subsidiaries were added as guarantors of our senior notes and corporate credit facility in June 2012 upon the termination of the midstream credit facility. All prior year information has been restated to reflect COS and its subsidiaries as non-guarantor subsidiaries and CMD and its subsidiaries as guarantor subsidiaries. Certain of our oilfield services subsidiaries, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain midstream and de minimis subsidiaries are not 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 September 30, 2012 and December 31, 2011 and for three and nine months ended September 30, 2012 and 2011. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

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CONDENSED CONSOLIDATING BALANCE SHEET
AS OF SEPTEMBER 30, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$—	$54	$88	$—	$142
Restricted cash	—	—	156	—	156
Other	1	3,087	520	(406)	3,202
Current assets held for sale	—	111	—	—	111
Total Current Assets	1	3,252	764	(406)	3,611
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	30,995	2,901	8	33,904
Other property and equipment at cost, net	—	2,774	1,618	—	4,392
Property and equipment held for sale, net	—	2,283	24	—	2,307
Total Property and Equipment, Net	—	36,052	4,543	8	40,603
LONG-TERM ASSETS:					
Other assets	288	1,099	319	(372)	1,334
Long-term assets held for sale	—	123	—	—	123
Investments in subsidiaries and intercompany advances	2,199	580	—	(2,779)	—
TOTAL ASSETS	$2,488	$41,106	$5,626	$(3,549)	$45,671
CURRENT LIABILITIES:					
Current liabilities	$762	$5,431	$444	$(357)	$6,280
Current liabilities held for sale	—	176	—	—	176
Intercompany payable to (receivable from) parent	(26,695)	26,531	202	(38)	—
Total Current Liabilities	(25,933)	32,138	646	(395)	6,456
LONG-TERM LIABILITIES:					
Long-term debt, net	12,983	1,785	987	—	15,755
Deferred income tax liabilities	73	3,142	206	(3)	3,418
Other liabilities	38	1,840	843	(372)	2,349
Long-term liabilities held for sale	—	2	—	—	2
Total Long-Term Liabilities	13,094	6,769	2,036	(375)	21,524
EQUITY:					
Chesapeake stockholders' equity	15,327	2,199	2,944	(5,143)	15,327
Noncontrolling interests	—	—	—	2,364	2,364
Total Equity	15,327	2,199	2,944	(2,779)	17,691
TOTAL LIABILITIES AND EQUITY	$2,488	$41,106	$5,626	$(3,549)	$45,671

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2011
($ in millions)

	Parent[a]	Guarantor Subsidiaries[a]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$—	$1	$350	$—	$351
Restricted cash	—	—	44	—	44
Other	1	2,734	259	(212)	2,782
Total Current Assets	1	2,735	653	(212)	3,177
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost, based on full cost accounting, net	—	29,659	2,017	(476)	31,200
Other property and equipment at cost, net	—	4,287	1,252	—	5,539
Total Property and Equipment, Net	—	33,946	3,269	(476)	36,739
LONG-TERM ASSETS:					
Other assets	161	2,015	120	(377)	1,919
Investments in subsidiaries and intercompany advances	3,501	177	—	(3,678)	—
TOTAL ASSETS	$3,663	$38,873	$4,042	$(4,743)	$41,835
CURRENT LIABILITIES:					
Current liabilities	$288	$6,709	$299	$(214)	$7,082
Intercompany payable to (receivable from) parent	(21,903)	21,489	651	(237)	—
Total Current Liabilities	(21,615)	28,198	950	(451)	7,082
LONG-TERM LIABILITIES:					
Long-term debt, net	8,226	1,720	680	—	10,626
Deferred income tax liabilities	390	3,135	196	(237)	3,484
Other liabilities	38	2,319	702	(377)	2,682
Total Long-Term Liabilities	8,654	7,174	1,578	(614)	16,792
EQUITY:					
Chesapeake stockholders' equity	16,624	3,501	1,514	(5,015)	16,624
Noncontrolling interests	—	—	—	1,337	1,337
Total Equity	16,624	3,501	1,514	(3,678)	17,961
TOTAL LIABILITIES AND EQUITY	$3,663	$38,873	$4,042	$(4,743)	$41,835

(a) We have revised the amounts presented as long-term debt in the Guarantor Subsidiaries and Parent columns to properly reflect the long-term debt issued by the Parent of $8.2 billion, which was incorrectly presented as long-term debt attributable to the Guarantor Subsidiaries as of December 31, 2011. The impact of this error was not material to our December 31, 2011 financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED SEPTEMBER 30, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES					
Natural gas, oil and NGL	$—	$1,357	$79	$1	$1,437
Marketing, gathering and compression	—	1,381	—	—	1,381
Oilfield services	—	—	487	(335)	152
Total Revenues	—	2,738	566	(334)	2,970
OPERATING EXPENSES					
Natural gas, oil and NGL production	—	312	8	—	320
Production taxes	—	51	2	—	53
Marketing, gathering and compression	—	1,338	1	—	1,339
Oilfield services	—	1	363	(248)	116
General and administrative	—	120	28	—	148
Natural gas, oil and NGL depreciation, depletion and amortization	—	717	45	—	762
Depreciation and amortization of other assets	—	43	59	(36)	66
Impairment of natural gas and oil properties	—	3,377	115	(177)	3,315
Losses on sales and impairments of fixed assets and other	—	4	41	—	45
Total Operating Expenses	—	5,963	662	(461)	6,164
INCOME (LOSS) FROM OPERATIONS	—	(3,225)	(96)	127	(3,194)
OTHER INCOME (EXPENSE)					
Interest expense	(289)	(18)	(20)	291	(36)
Earnings (losses) on investments	—	(24)	1	—	(23)
Gains on sales of investments	—	31	—	—	31
Other income (expense)	285	5	4	(303)	(9)
Equity in net earnings of subsidiary	(2,010)	(147)	—	2,157	—
Total Other Income (Expense)	(2,014)	(153)	(15)	2,145	(37)
INCOME (LOSS) BEFORE INCOME TAXES	(2,014)	(3,378)	(111)	2,272	(3,231)
INCOME TAX EXPENSE (BENEFIT)	(2)	(1,260)	(43)	45	(1,260)
NET INCOME (LOSS)	(2,012)	(2,118)	(68)	2,227	(1,971)
Net income attributable to noncontrolling interests	—	—	—	(41)	(41)
NET INCOME (LOSS) ATTRIBUTABLE TO	(2,012)	(2,118)	(68)	2,186	(2,012)

CHESAPEAKE					
Other comprehensive income (loss)	3	(9)	—	—	(6)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(2,009)	$(2,127)	$(68)	$2,186	$(2,018)

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CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED SEPTEMBER 30, 2011
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$2,402	$—	$—	$2,402
Marketing, gathering and compression	—	1,422	—	—	1,422
Oilfield services	—	—	344	(191)	153
Total Revenues	—	3,824	344	(191)	3,977
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	282	—	—	282
Production taxes	—	50	—	—	50
Marketing, gathering and compression	—	1,392	—	—	1,392
Oilfield services	—	1	254	(137)	118
General and administrative	—	137	14	—	151
Natural gas, oil and NGL depreciation, depletion and amortization	—	423	—	—	423
Depreciation and amortization of other assets	—	56	41	(22)	75
Losses on sales and impairments of fixed assets and other	—	3	—	—	3
Total Operating Expenses	—	2,344	309	(159)	2,494
INCOME (LOSS) FROM OPERATIONS	—	1,480	35	(32)	1,483
OTHER INCOME (EXPENSE):					
Interest expense	(138)	—	(15)	149	(4)
Earnings (losses) on investments	—	28	—	—	28
Losses on purchases or exchanges of debt	—	—	—	—	—
Other income	151	2	6	(155)	4
Equity in net earnings of subsidiary	914	(7)	—	(907)	—
Total Other Income (Expense)	927	23	(9)	(913)	28
INCOME (LOSS) BEFORE INCOME TAXES	927	1,503	26	(945)	1,511
INCOME TAX EXPENSE (BENEFIT)	5	589	10	(15)	589
NET INCOME (LOSS)	922	914	16	(930)	922
Net income attributable to noncontrolling interests	—	—	—	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	922	914	16	(930)	922
Other comprehensive income (loss)	—	(6)	—	—	(6)
	$922	$908	$16	$(930)	$916

COMPREHENSIVE INCOME (LOSS)
ATTRIBUTABLE TO CHESAPEAKE

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$4,410	$209	$3	$4,622
Marketing, gathering and compression	—	3,709	1	—	3,710
Oilfield services	—	—	1,440	(994)	446
Total Revenues	—	8,119	1,650	(991)	8,778
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	990	15	—	1,005
Production taxes	—	137	4	—	141
Marketing, gathering and compression	—	3,629	2	—	3,631
Oilfield services	—	2	1,028	(709)	321
General and administrative	—	370	70	—	440
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,762	94	—	1,856
Depreciation and amortization of other assets	—	168	170	(105)	233
Impairment of natural gas and oil properties	—	3,377	133	(195)	3,315
Losses on sales and impairments of fixed assets and other	—	221	65	—	286
Total Operating Expenses	—	10,656	1,581	(1,009)	11,228
INCOME (LOSS) FROM OPERATIONS	—	(2,537)	69	18	(2,450)
OTHER INCOME (EXPENSE):					
Interest expense	(682)	(10)	(57)	686	(63)
Earnings (losses) on investments	—	(93)	6	—	(87)
Gains on sales of investments	—	1,061	—	—	1,061
Losses on purchases or exchanges of debt	—	—	—	—	—
Other income	667	28	11	(704)	2
Equity in net earnings of subsidiary	(1,059)	(232)	—	1,291	—
Total Other Income (Expense)	(1,074)	754	(40)	1,273	913
INCOME (LOSS) BEFORE INCOME TAXES	(1,074)	(1,783)	29	1,291	(1,537)
INCOME TAX EXPENSE (BENEFIT)	(5)	(605)	11	—	(599)
NET INCOME (LOSS)	(1,069)	(1,178)	18	1,291	(938)
Net income attributable to noncontrolling interests	—	—	—	(131)	(131)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(1,069)	(1,178)	18	1,160	(1,069)

Other comprehensive income (loss)	2	(24)	—	—	(22)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(1,067)	$(1,202)	$18	$1,160	$(1,091)

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(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2011
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$4,688	$—	$—	$4,688
Marketing, gathering and compression	—	3,844	—	—	3,844
Oilfield services	—	—	867	(491)	376
Total Revenues	—	8,532	867	(491)	8,908
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	782	—	—	782
Production taxes	—	140	—	—	140
Marketing, gathering and compression	—	3,744	—	—	3,744
Oilfield services	—	1	641	(355)	287
General and administrative	—	382	28	—	410
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,147	—	—	1,147
Depreciation and amortization of other assets	—	158	106	(58)	206
Losses on sales and impairments of fixed assets and other	—	7	—	—	7
Total Operating Expenses	—	6,361	775	(413)	6,723
INCOME (LOSS) FROM OPERATIONS	—	2,171	92	(78)	2,185
OTHER INCOME (EXPENSE):					
Interest expense	(488)	(10)	(33)	494	(37)
Earnings on investments	—	100	—	—	100
Losses on purchases or exchanges of debt	(176)	—	—	—	(176)
Other income	494	10	8	(503)	9
Equity in net earnings of subsidiary	1,373	(12)	—	(1,361)	—
Total Other Income (Expense)	1,203	88	(25)	(1,370)	(104)
INCOME (LOSS) BEFORE INCOME TAXES	1,203	2,259	67	(1,448)	2,081
INCOME TAX EXPENSE (BENEFIT)	(66)	886	26	(34)	812
NET INCOME (LOSS)	1,269	1,373	41	(1,414)	1,269
Net income attributable to noncontrolling interests	—	—	—	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,269	1,373	41	(1,414)	1,269
Other comprehensive income (loss)	3	59	—	—	62
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$1,272	$1,432	$41	$(1,414)	$1,331

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
NINE MONTHS ENDED SEPTEMBER 30, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$1,814	$164	$—	$1,978
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(9,891)	(447)	—	(10,338)
Proceeds from divestitures of proved and unproved properties	—	2,204	241	—	2,445
Additions to other property and equipment	—	(1,323)	(593)	—	(1,916)
Other investing activities	—	2,715	(246)	(814)	1,655
Cash used in investing activities	—	(6,295)	(1,045)	(814)	(8,154)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	12,926	1,060	—	13,986
Payments on credit facilities borrowings	—	(12,862)	(752)	—	(13,614)
Proceeds from issuance of term loans, net of discount and offering costs	3,789	—	—	—	3,789
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	—	—	—	1,263
Cash paid to purchase debt	—	—	—	—	—
Proceeds from sales of noncontrolling interests	—	—	1,056	—	1,056
Other financing activities	(367)	(178)	(768)	814	(499)
Intercompany advances, net	(4,685)	4,648	37	—	—
Cash provided by financing activities	—	4,534	633	814	5,981
Change in cash and cash equivalents classified in current assets held for sale	—	—	(14)	—	(14)
Net increase (decrease) in cash and cash equivalents	—	53	(262)	—	(209)
Cash and cash equivalents, beginning of period	—	1	350	—	351
Cash and cash equivalents, end of period	$—	$54	$88	$—	$142

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
NINE MONTHS ENDED SEPTEMBER 30, 2011
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$3,683	$41	$—	$3,724
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(9,118)	—	—	(9,118)
Proceeds from divestitures of proved and unproved properties	—	6,357	—	—	6,357
Additions to other property and equipment	—	(778)	(638)	—	(1,416)
Other investing activities	—	(130)	95	497	462
Cash used in investing activities	—	(3,669)	(543)	497	(3,715)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	11,914	—	—	11,914
Payments on credit facilities borrowings	—	(12,057)	—	—	(12,057)
Proceeds from issuance of senior notes, net of discount and offering costs	977	—	—	—	977
Cash paid to purchase debt	(2,015)	—	—	—	(2,015)
Proceeds from sales of noncontrolling interests	—	—	—	—	—
Other financing activities	(393)	1,567	504	(497)	1,181
Intercompany advances, net	1,431	(1,438)	7	—	—
Cash provided by financing activities	—	(14)	511	(497)	—
Change in cash and cash equivalents classified in current assets held for sale	—	—	—	—	—
Net increase (decrease) in cash and cash equivalents	—	—	9	—	9
Cash and cash equivalents, beginning of period	—	102	—	—	102
Cash and cash equivalents, end of period	$—	$102	$9	$—	$111

15. Recently Issued and Proposed Accounting Standards

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

In December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company's financial statements to understand the effect of those arrangements on its financial position. The standard is effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. In December 2011, the FASB deferred the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income. This guidance will not have an impact on our financial position or results of operations.

In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements which expands existing fair value disclosure requirements, particularly for Level 3 inputs. The new requirements include quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs; and the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed. The guidance was effective for interim and annual periods beginning on or after December 15, 2011. Adoption had no impact on our financial position or results of operations.

16. Subsequent Events

In October 2012, we sold our Delaware Basin assets in the Permian Basin to SWEPI LP, a subsidiary of Royal Dutch Shell plc (NYSE:RDS.B), and Chevron U.S.A. Inc., a subsidiary of Chevron Corporation (NYSE:CVX) for net cash proceeds of approximately $2.715 billion. Payment of up to $466 million in remaining proceeds will be subject to certain title, environmental and other standard contingencies, and we expect to receive the majority of the remaining proceeds over the next eighteen months. We used the net proceeds received from these transactions to reduce the outstanding balance on our existing term loans. See Note 3 for further discussion of the term loan repayments.

In conjunction with these transactions, affiliates of Mr. McClendon also sold interests in the same properties that were acquired through the FWPP on the same terms as those that applied to the properties held by the Company. In addition, those affiliates will receive their proportionate share of the remaining proceeds as they are paid.

See Note 9 regarding the sale of our remaining interest in Glass Mountain Pipeline, LLC which occurred in October 2012. We used the net proceeds from the sale to reduce the outstanding balance on our existing term loans.

On November 9, 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. Our obligations under the new 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 new facility, which priced at 98% of par, bear interest at LIBOR plus 4.5%. The LIBOR rate is subject to a floor of 1.25% per annum. The new facility is non-callable in the first year but 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. We used the net proceeds of the new term loan to fully repay the remaining outstanding borrowings under our existing term loans and to repay outstanding borrowings under the Company's corporate revolving bank credit facility.

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

Overview

The following table sets forth certain information regarding the production volumes, natural gas, oil and NGL sales, average sales prices received, other operating income and expenses for the three and nine months ended September 30, 2012 (the "Current Quarter" and the "Current Period", respectively) and the three and nine months ended September 30, 2011 (the "Prior Quarter" and the "Prior Period", respectively):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Production:				
Natural gas (bcf)	302.3	254.2	848.6	731.9
Oil (mmbbl)	9.0	4.6	22.3	11.7
NGL (mmbbl)	4.1	4.1	13.0	10.2
Natural gas equivalent (bcfe)[a]	381.1	306.2	1,060.5	863.3
Natural Gas, Oil and NGL Sales ($ in millions):				
Natural gas sales	$543	$861	$1,359	$2,412
Natural gas derivatives – realized gains (losses)	52	364	391	1,322
Natural gas derivatives – unrealized gains (losses)	(90)	(28)	(401)	(693)
Total natural gas sales	505	1,197	1,349	3,041
Oil sales	792	386	2,038	1,048
Oil derivatives – realized gains (losses)	25	(8)	6	(51)
Oil derivatives – unrealized gains (losses)	(14)	645	803	247
Total oil sales	803	1,023	2,847	1,244
NGL sales	129	180	401	432
NGL derivatives – realized gains (losses)	—	(12)	(9)	(31)
NGL derivatives – unrealized gains (losses)	—	14	34	2
Total NGL sales	129	182	426	403
Total natural gas, oil and NGL sales	$1,437	$2,402	$4,622	$4,688
Average Sales Price (excluding gains (losses) on derivatives):				
Natural gas ($ per mcf)	$1.80	$3.39	$1.60	$3.30
Oil ($ per bbl)	$88.07	$84.18	$91.31	$89.78
NGL ($ per bbl)	$31.22	$44.04	$30.86	$42.17
Natural gas equivalent ($ per mcfe)	$3.84	$4.66	$3.58	$4.51
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$1.97	$4.82	$2.06	$5.10
Oil ($ per bbl)	$90.79	$82.47	$91.55	$85.45
NGL ($ per bbl)	$31.22	$41.16	$30.17	$39.10
Natural gas equivalent ($ per mcfe)	$4.04	$5.78	$3.95	$5.94
Other Operating Income[b] ($ in millions):				
Marketing, gathering and compression net margin	$42	$30	$79	$100
Oilfield services net margin	$36	$35	$125	$89
Other Operating Income[b] ($ per mcfe):				
Marketing, gathering and compression net margin	$0.11	$0.10	$0.07	$0.12
Oilfield services net margin	$0.09	$0.11	$0.12	$0.10

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Expenses ($ per mcfe):				
Natural gas, oil and NGL production	$0.84	$0.92	$0.95	$0.91
Production taxes	$0.14	$0.16	$0.13	$0.16
General and administrative expenses	$0.39	$0.49	$0.41	$0.47
Natural gas, oil and NGL depreciation, depletion and amortization	$2.00	$1.38	$1.75	$1.33
Depreciation and amortization of other assets	$0.17	$0.24	$0.22	$0.24
Interest expense[c]	$0.10	$0.01	$0.06	$0.03
Interest Expense ($ in millions):				
Interest expense	$38	$4	$67	$18
Interest rate derivatives – realized (gains) losses	—	—	—	6
Interest rate derivatives – unrealized (gains) losses	(2)	—	(4)	13
Total interest expense	$36	$4	$63	$37

(a) Natural gas equivalent is based on six mcf of natural gas to one barrel of oil or one barrel of natural gas liquids (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.

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

We are the second-largest producer of natural gas, a top 12 producer of oil and NGL (collectively “liquids”) and the most active driller of wells in the U.S. We own interests in approximately 46,700 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. natural gas assets in the Haynesville and Bossier Shales in northwestern Louisiana and East Texas; the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania; and the 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, Cleveland, Tonkawa and Hogshooter plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle; the Mississippi Lime play on the Anadarko Basin Shelf in northern Oklahoma and southern Kansas; and the Niobrara Shale in the Powder River Basin in Wyoming. We have also vertically integrated many of our operations and own substantial midstream, compression and oilfield services assets.

Proved Reserves. Chesapeake began 2012 with estimated proved reserves of 18.789 tcfe and ended the Current Period with 16.222 tcfe, a decrease of 2.567 tcfe, or 14%. The Current Period’s proved reserve movement included 1.060 tcfe of production, 4.474 tcfe of extensions, 4.878 tcfe of downward revisions resulting primarily from lower natural gas prices using the average first-day-of-the-month price for the twelve months ended September 30, 2012, compared to the twelve months ended December 31, 2011, and 596 bcfe of other downward revisions. During the Current Period, we acquired 37 bcfe of estimated proved reserves and divested 544 bcfe of estimated proved reserves.

In the Current Period, we reduced our estimate of proved reserves by 5.474 tcfe primarily due to the impact of lower natural gas prices. Natural gas prices used in estimating proved reserves as of September 30, 2012 decreased by $1.29, or 31%, to $2.83 per mcf from $4.12 per mcf as of December 31, 2011 using the trailing 12-month average prices required by the Securities and Exchange Commission (SEC). The reserve reductions included the loss of significant proved undeveloped reserves, primarily in the Barnett Shale and the Haynesville Shale plays, for which future development is uneconomic at the natural gas prices used in the reserves estimates. As a result of lower estimated reserves, as of September 30, 2012, we were required to impair the carrying value of our natural gas and oil properties and, if the trailing 12-month natural gas, oil and NGL prices are lower in subsequent future periods, we could have additional impairments in the future. An impairment of this type is a non-cash charge that does not impact our liquidity or our ability to comply with financial covenants. 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. We refer you to the risk factor "Declines in the prices of natural gas and oil could result in a write-down of our asset carrying values" included in Item 1A of our 2011 Form 10-K and the discussion of the full cost method of accounting under Application of Critical Accounting Policies – Natural Gas and Oil Properties in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of our 2011 Form 10-K. In addition, see Natural Gas and Oil Properties in Note 1 of our condensed consolidated financial statements included in Part 1, Item 1 of this report.
Drilling and Completion Expenditures. During the Current Period, we invested $7.360 billion in drilling and completion costs on proved and unproved properties, of which approximately 90% was related to operated wells (using an average of 145 operated rigs) and approximately 10% was related to non-operated wells (using an average of 72 non-operated rigs).
Production. Our Current Quarter production of 381.1 bcfe consisted of 302.3 bcf of natural gas (79% on a natural gas equivalent basis), 9.0 mmbbls of oil (14% on a natural gas equivalent basis) and 4.1 mmbbls of NGL (7% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 4.142 bcfe, an increase of 813 mmcfe, or 24%, over the 3.329 bcfe produced per day in the Prior Quarter.
Our Current Period production of 1,060.5 bcfe consisted of 848.6 bcf of natural gas (80% on a natural gas equivalent basis), 22.3 mmbbls of oil (13% on a natural gas equivalent basis) and 13.0 mmbbls of NGL (7% on a natural gas equivalent basis). Daily production for the Current Period averaged 3.870 bcfe, an increase of 708 mmcfe, or 22%, over the 3.162 bcfe produced per day in the Prior Period.
During the first half of 2012, Chesapeake curtailed approximately 60 bcf of net natural gas production, or an average of approximately 220 mmcf per day of natural gas spread across the Current Period. We undertook these curtailments in response to continued low natural gas prices. The curtailed volumes were located primarily in the Haynesville and Barnett shale plays. We ended our natural gas production curtailment program at the end of the 2012 second quarter.
Leasehold and Seismic Inventories. Since 2000, Chesapeake has built a leading position in 10 of what we believe are the top 15 unconventional plays in the U.S. We are currently using 88 operated drilling rigs (net of nine rigs we are operating on behalf of purchasers of our Delaware Basin assets in the Permian Basin) to further develop our leasehold inventory. We are targeting to invest approximately $1.750 billion in undeveloped leasehold expenditures, net of reimbursements from joint venture partners, in 2012, of which approximately 90% will be in liquids-rich plays and all of which will be in plays where the Company is already active. This compares to net undeveloped leasehold expenditures of approximately $3.5 billion and $5.8 billion in 2011 and 2010, respectively.
Emphasis on Increasing Liquids Production. In recognition of the value gap between liquids and natural gas prices, Chesapeake has 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. This planned transition will result in a more balanced and, we believe, more profitable portfolio between natural gas and liquids. In the Current Period, our production of liquids averaged approximately 128,900 bbls per day, a 61% increase over the Prior Period average, as a result of the increased development of our unconventional liquids-rich plays. We project that the portion of our operated drilling and completion expenditures allocated to liquids development will reach approximately 85% in 2012, and we expect to increase our liquids production through our drilling activities to an average of approximately 130,000 bbls per day in 2012, 170,000 bbls per day in 2013 and to reach 250,000 bbls per day in 2015.
Sales. Our business strategy is to create value for investors by building, developing and now harvesting what we believe is the largest onshore natural gas and liquids-rich resource base in the U.S. After years of building our resource base, we plan to focus on the 10 plays where we have a #1 or #2 ownership position and to sell assets that are non-core or do not fit our long-term plans. During the Current Period, we completed sales for proceeds of approximately $5.7 billion, have completed sales through November 7, 2012 for $8.4 billion and we have announced our intention to sell natural gas and oil properties, midstream, oilfield services and other assets that will bring expected total proceeds to $17 - $19 billion in 2012 - 2013. Our sales program, together with operating cash flow and borrowings under our corporate revolving bank credit facility, is designed to fully fund the Company's 2012 capital expenditure program and reduce the Company's long-term debt, although we may not reach our previously announced goal of $9.5 billion by year-end 2012 until 2013. In 2013, we expect to continue to sell assets to supplement operating

cash flow to fund capital expenditures and maintain long-term debt at no more than $9.5 billion. We refer you to risks associated with our sales plans, as described in Planned Sales below.

Capital Expenditures

In the Current Period, our capital expenditures for exploration, development and acquisition activities, net of drilling and completion carries of $655 million, were $9.550 billion, including $7.360 billion for drilling and completion costs, $1.850 billion for acquisitions of unproved properties (excluding $228 million of reimbursements for unproved leasehold from our joint venture partners) and $340 million for acquisitions of proved properties. We incurred a disproportionately high percentage of our total budgeted 2012 capital expenditures early in the year as the result of several factors which are discussed further below. Our current budget for 2012 includes drilling and completion capital expenditures, net of drilling and completion carries, of $8.750 billion and undeveloped leasehold expenditures of $2.030 billion, excluding reimbursements for unproved leasehold from our joint venture partners. We anticipate receiving approximately $280 million in reimbursements for unproved leasehold from our joint venture partners in 2012.

Drilling and completion costs during the Current Period reflected the impact of our deliberate transition to liquids-focused drilling and reduced natural gas drilling. During the 2012 first quarter, our 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. As of November 1, 2012, our rig count had been reduced to 88 rigs (net of nine rigs we are currently operating on behalf of purchasers of our Delaware Basin assets in the Permian Basin). Our budget reflects sharp reductions in our natural gas drilling activities, from 50 rigs at the beginning of 2012 to an average of 9 rigs in the fourth quarter of 2012. The Current Period drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled in prior periods. These completions, which we expect will represent more than 50% of all natural gas wells we complete during 2012, enabled us to hold by production the related leasehold according to the terms of our leases. For 2013, we are budgeting $5.750 – $6.250 billion for drilling and completion capital expenditures, net of drilling and completion carries, and $500 million for new leasehold expenditures, excluding reimbursements for unproved leasehold from our joint venture partners. We anticipate receiving approximately $100 million in reimbursements for unproved leasehold from our joint venture partners in 2013.

Approximately 75% of our leasehold acquisition costs during the Current Period were focused on adding acreage in the Utica, Marcellus and Mid-Continent plays. As described above, we anticipate significantly lower leasehold spending in the remainder of 2012 and 2013. Having captured what we believe are the most promising areas of our core plays, we have now shifted our focus to developing these assets.

Capital expenditures related to our midstream, oilfield services and other assets were approximately $2.295 billion during the Current Period and are projected to be $2.8 – $3.1 billion and $850 million – $1.1 billion in 2012 and 2013, respectively. We estimate that the divestiture of our midstream business, as discussed in Planned Sales below, will enable us to reduce previously budgeted capital expenditures by approximately $1.0 – $1.250 billion in 2013 and approximately $3.0 billion over the three years ending 2015.

Through the vertical integration of our oilfield services business 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. If our access to funds from planned asset sales or from other sources were limited, however, our ability to develop and replace our reserves could be reduced. Management and the board of directors are currently reviewing operational plans for 2013 and beyond, which could result in changes to the Company's drilling activity and projected production levels in 2013.

Recent Sales

An essential part of our business strategy in 2012 and 2013 is using the proceeds from sales to reduce our indebtedness and to fund the capital expenditures needed to transition from a natural gas-focused drilling program to a liquids-focused drilling program. Below we describe transactions completed in 2012 and the continuing benefits of our joint ventures which were completed prior to 2012.

Asset Sales

Permian Basin. We sold the vast majority of our Permian Basin assets, representing approximately 6% of our total proved reserves as of June 30, 2012 and 6% of our 2012 second quarter net production, in separate transactions in the second half of 2012. In September 2012, we sold our producing assets in the Midland Basin portion of the Permian Basin to affiliates of Houston-based EnerVest, Ltd. for proceeds of approximately $376 million in cash. In October 2012, we sold our assets in the Delaware Basin portion of the Permian Basin to SWEPI LP, a subsidiary of

Royal Dutch Shell plc (NYSE:RDS.B), and Chevron U.S.A. Inc., a subsidiary of Chevron Corporation (NYSE:CVX), and received approximately $2.715 billion in cash. An additional $466 million of consideration is subject to certain title, environmental and other standard contingencies, the majority of which we expect to receive in the next eighteen months.

In September 2012, to facilitate the sales process associated with our Permian Basin divestiture packages, we purchased the remaining reserves from our Permian Basin volumetric production payment (VPP), originally entered into in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets described above.

Non-Core Utica Shale. In August 2012, we sold approximately 72,000 net acres of non-core leasehold in the Utica shale play in Ohio to affiliates of EnerVest for approximately $358 million in cash.

Texoma Woodford. In April 2012, we sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Bryan, Carter, Johnston and Marshall counties in Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for approximately $572 million in cash. The properties included approximately 25 mmcfe per day of current net production.

Under full cost accounting rules, we account for the sale of natural gas and oil properties in the sales transactions described above as an adjustment to capitalized costs, with no recognition of gain or loss. In conjunction with the sales transactions, affiliates of our 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 proceeds were paid to the sellers based on their respective ownership. These interests were acquired through the Founders Well Participation Program (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.

Sale of Investment in Chesapeake Midstream Partners, L.P.

In June 2012, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners (GIP) for cash proceeds of $2.0 billion. We recorded a $1.032 billion pre-tax gain associated with the transaction.

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 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. For further discussion, see Noncontrolling Interests in Note 6 of the notes to our condensed consolidated financial statements included in Part I, Item 1 of this report.

Volumetric Production Payment (VPP)

In March 2012, we monetized certain of our producing assets in the Anadarko Basin Granite Wash through a ten-year VPP for proceeds of approximately $744 million. The transaction included approximately 160 bcfe of proved reserves and approximately 125 mmcfe per day of net production. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and we also retain all production beyond the specified volumes sold in the transaction. This transaction was our tenth VPP. The cash proceeds from this transaction were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Other VPPs we completed in 2007 – 2011 are detailed in Note 8 of the notes to our condensed consolidated financial statements included in Part I, Item 1 of this report.

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Joint Ventures

As of September 30, 2012, 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 for future drilling and completion cost sharing of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all leasing, drilling, completion, operations and marketing activities for the project. The carry obligations paid by a joint venture partner are for a specified percentage of our drilling and completion cost obligations. 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. Our joint venture transactions have allowed us to recover much or all of our initial leasehold investments and reduce our ongoing capital costs in these plays. 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		$2,032	$1,249
Niobrara	CNOOC	February 2011	33.3%	570	697		1,267	495
Eagle Ford	CNOOC	November 2010	33.3%	1,120	1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800	1,404	(c)	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	(d)	3,158	—
				$7,100	$9,036		$16,136	$1,744

(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 September 30, 2012. The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. 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. See Note 4 of the notes to our condensed consolidated financial statements included in Part I, Item 1 of this report for further discussion of the Utica drilling carries.

(c) In conjunction with an agreement requiring us to maintain our operated rig count at no less than 12 rigs in the Barnett Shale through December 31, 2012, TOT accelerated the payment of its remaining joint venture drilling carry in exchange for an approximate 9% reduction in the total amount of drilling carry obligation owed to us at that time. As a result, in October 2011, we received $471 million in cash from TOT, which included $46 million of drilling carry obligation billed and $425 million for the remaining drilling carry obligation. In January 2012, Chesapeake and TOT agreed to reduce the minimum rig count from 12 to six rigs. In May 2012, Chesapeake and TOT agreed to further reduce the minimum rig count from six to two rigs.

(d) In September 2009, PXP accelerated the payment of its remaining drilling carry in exchange for an approximate 12% reduction to the remaining drilling carry obligation owed to us at that time.

The drilling and completion carries in our joint venture agreements allow us to reduce our finding costs. During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $655 million and $1.868 billion, respectively, of drilling and completion carries paid by our joint venture partners, CNOOC, TOT and STO. Our drilling and completion costs for 2012, 2013 and 2014 will continue to be partially offset by the use of the remaining drilling and completion carries associated with our joint venture agreements. Once the remaining carries have been used, we anticipate our net drilling and completion costs to increase.

During the Current Period, as part of our joint venture agreements with TOT and STO, we sold interests in additional leasehold we acquired in the Marcellus, Barnett and Utica shale plays to our joint venture partners for approximately $228 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

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Planned Sales

We have entered into a letter agreement relating to the potential sale of certain Mid-Continent gathering and processing assets to ACMP and a separate letter agreement with GIP for the potential sale of our wholly owned subsidiary, Chesapeake Midstream Operating, L.L.C. (CMO), to GIP. The parties to the GIP letter agreement have agreed to an exclusive negotiation and we anticipate completing these sales in the 2012 fourth quarter.

We are also pursuing a sale or joint venture transaction for certain of our Mississippi Lime properties in northern Oklahoma and southern Kansas, where we own approximately 2.0 million net acres. We anticipate entering into this transaction in the 2012 fourth quarter. In addition, we have other assets currently for sale, including our northern Eagle Ford assets, our Chitwood-Knox assets in Grady, Stephens and Garvin counties, Oklahoma, and various portions of our Marcellus and Utica leasehold in Pennsylvania and Ohio that we consider non-core.

In April 2012, our wholly owned service industry affiliate, Chesapeake Oilfield Services, Inc., filed a registration statement with the SEC relating to the proposed initial public offering of shares of its Class A common stock. Application will be made to list the Class A common stock on the New York Stock Exchange under the symbol “COS”. There can be no assurance that we will complete this transaction, as it is subject to market conditions and other uncertainties, as well as completion of the SEC review process.

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 is not completed in the anticipated time frame or at all or for less proceeds than expected, our ability to fund budgeted capital expenditures, reduce our indebtedness as planned and maintain our compliance with revolving bank credit agreement covenants could be adversely affected.

Recent Developments

On November 9, 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. Our obligations under the new 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 new facility, which priced at 98% of par, bear interest at LIBOR plus 4.5%. The LIBOR rate is subject to a floor of 1.25% per annum. The new facility is non-callable in the first year but 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. We used the net proceeds of the new term loan to fully repay the remaining outstanding borrowings under our existing term loans and to repay outstanding borrowings under the Company's corporate revolving bank credit facility.

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Liquidity and Capital Resources

Liquidity Overview

Our business strategy is to continue our reserves and production growth and transition our asset base from an exclusive focus on natural gas production to a focus that is, and in the future will remain, more balanced between natural gas and liquids production. This is a capital-intensive strategy, particularly as spending for liquids drilling ramped up quickly in early 2012 even as our natural gas drilling continued, although at a slowing pace. We made capital expenditures in the Current Period that significantly exceeded our cash flow from operations. During the Current Period, the combination of high front-end capital expenditures and reduced cash flow as a result of low natural gas prices required us to increase our debt, net of unrestricted cash, by approximately $5.8 billion, to $16.1 billion, to fund our capital expenditure needs. Subsequent to September 30, 2012, we prepaid approximately $2.8 billion of our $4.0 billion of term loans with proceeds from asset sales, thereby reducing our long-term debt, and we repaid the remaining outstanding balance under the term loans of approximately $1.2 billion using a portion of the proceeds from the issuance of the new term loan described in Recent Developments.

As of September 30, 2012, we had approximately $2.5 billion in cash availability compared to $3.2 billion as of December 31, 2011. Including cash availability, as of September 30, 2012, we had negative working capital of approximately $466 million compared to negative working capital of approximately $1.084 billion as of December 31, 2011. Working capital deficits have existed largely because our capital spending generally has exceeded our cash flow from operations. Changes in working capital are primarily a result of the timing of the collection of receivables, drilling activities, payments made by us to vendors and other operators, the timing and amount of advances received from our joint operations and revenues due to other interest owners.

For the remainder of 2012 and 2013, we plan to fund capital expenditures with operating cash flow, borrowings under our corporate revolving bank credit facility and proceeds from various sales. We intend to sell natural gas and oil properties, midstream, oilfield services and other assets for expected total proceeds of $17 - $19 billion in 2012 - 2013. Through November 7, 2012, we have completed sales in 2012 for proceeds of approximately $8.4 billion. Any remaining cash available after applying these proceeds to the deficit between capital expenditures and operating cash flow will be available to further reduce our long-term debt. Additionally, 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.

The following table presents our budgeted operating cash flow, capital expenditures and certain other uses of cash for 2012 and 2013:

	Year Ending December 31, 2012	Year Ending December 31, 2013
	($ in millions)	
Operating cash flow before changes in assets and liabilities[(a)]	$3,800	$4,250 - $5,250
Drilling and completion costs	($8,750)	($5,750 - $6,250)
Acquisition of unproved properties, net[(b)]	($1,750)	($400)
Investment in oilfield services, midstream and other	($2,800 - $3,100)	($850 - $1,100)
Interest, dividends and cash taxes	($1,100 - $1,350)	($1,000 - $1,250)

(a) A non-GAAP financial measure. We are unable to provide a reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities. Assumes NYMEX prices on open contracts of $3.50 per mcf and $90.00 per bbl in 2012 and $3.50 - $4.50 per mcf and $90.00 per bbl for 2013.

(b) Net of reimbursement from joint venture partners.

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. Thus, the assets we select and schedule for sales, our budgeted capital expenditures and our natural gas, oil and NGL price forecasts are carefully considered as we project our future ability to comply with the financial covenant maintenance requirements of our corporate revolving bank credit facility. In September 2012, the existing leverage ratio covenant was increased through an amendment to the credit facility agreement. See Corporate Credit Facility below for discussion of the terms of the amendment. We would have been unable to meet the required ratio as of September 30, 2012 without this amendment primarily because the closing of asset sales transactions occurred in the fourth quarter and not in September as we had anticipated. As a result, without the amendment, we would have been unable to reduce our indebtedness sufficiently as of September 30, 2012 to maintain our covenant compliance. The amendment relaxes our required indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. Failure to maintain compliance with the covenants of our revolving bank credit facility agreement would, absent a waiver or amendment, allow lenders to declare an event of default and cause any outstanding indebtedness under the agreement to become immediately due and payable. Such action could also lead to cross defaults under our senior note and contingent convertible senior note indentures.

Sustained low natural gas prices, and volatile natural gas, oil and NGL prices in general, could have a material adverse effect on our financial position, results of operations and cash flows, which could adversely impact our ability to comply with financial covenants under our corporate revolving bank credit facility and further limit our ability to fund our planned capital expenditures and reduce indebtedness. In addition, sustained low natural gas, oil and NGL prices could result in a reduction in the estimated quantity of proved reserves we report and in the estimated future net cash flows expected to be generated from our proved reserves. As a result, we may be required to further impair the carrying value of our natural gas and oil properties, and such amounts could be material.

With the proceeds of the new $2 billion term loan we closed on November 9, 2012 (see Recent Developments above), we paid in full the May 2012 term loans, and we expect to have adequate liquidity to repay $464 million of senior note indebtedness that matures in 2013. We have significant other contractual cash obligations to third parties pursuant to various arrangements, agreements and investments described in Note 4 of the notes to our condensed consolidated financial statements included in Part 1, Item 1 of this report. We expect to meet these performance and payment commitments in the ordinary course of business, recognizing that we may be required to meet such obligations even if our business plan assumptions were to change due to circumstances beyond our control.

Based on ongoing reductions in our capital expenditures, expected commodity prices as reflected in futures prices and prices for our currently hedged production, our forecasted drilling and production, projected levels of indebtedness and certain asset sales presently being negotiated, we believe we will be in compliance with the financial maintenance covenants, including the amended leverage ratios, of our corporate revolving bank credit facility, and we will have adequate liquidity, through 2013. 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. Management and the board of directors continue to review operations for 2013 and beyond, which could result in changes to projected capital expenditures and revenues from sales of natural gas, oil and NGL in 2013.

Sources and Uses of Cash

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

	Nine Months Ended September 30,	
	2012	2011
	($ in millions)	
Sources of cash and cash equivalents:		
Operating cash flow	$1,978	$3,724
Sales of natural gas and oil assets	2,445	6,357
Proceeds from sales of other assets	219	682
Net proceeds from investments	1,739	126
Proceeds from long-term debt	5,052	977
Proceeds from credit facility borrowings	13,986	11,914
Proceeds from sales of noncontrolling interests	1,056	—
Cash received from financing derivatives	—	1,085
Other	225	489
Total sources of cash and cash equivalents	26,700	25,354
Uses of cash and cash equivalents:		
Natural gas and oil expenditures	(10,338)	(9,118)
Additions to other property and equipment	(1,916)	(1,416)
Acquisition of drilling company	—	(339)
Payments of credit facility borrowings	(13,614)	(12,057)
Cash paid to purchase debt	—	(2,015)
Dividends paid	(298)	(279)
Distributions to noncontrolling interest owners	(163)	—
Cash paid for financing derivatives	(36)	—
Other	(530)	(121)
Total uses of cash and cash equivalents	(26,895)	(25,345)
Change in cash and cash equivalents held for sale	(14)	—
Change in cash and cash equivalents	$(209)	$9

Sources of Funds

Cash flow from operations is a source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $1.978 billion in the Current Period compared to $3.724 billion in the Prior Period. The decline in cash flow from operations is primarily the result of a decrease in the realized natural gas price (excluding the effect of unrealized gains or losses on derivatives) from $5.10 per mcf in the Prior Period to $2.06 per mcf in the Current Period. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, impairments, natural gas and oil properties, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under Results of Operations.

The volatility in the energy markets makes it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty, leaving us exposed to potential reduction in our operating cash flow and therefore affecting our ability to fund our capital expenditures. To mitigate the risk of declines in these prices and to provide more predictable future cash flow from operations, we have entered into various derivative instruments which have hedged approximately 76% of our forecasted 2012 fourth quarter natural gas and oil production and approximately 69% of our 2013 forecasted oil production. Our 2013 natural gas production is currently unhedged. Our natural gas, oil and NGL derivatives as of September 30, 2012 are detailed in Part I, Item 3 of this report. Depending on changes in natural gas, oil and NGL futures markets and management's view of underlying natural gas, oil and NGL supply and demand trends, we may increase or decrease our current derivative positions. As natural gas, oil and NGL prices decline and reach supportable low prices, however, we may close out open swap positions to lock in mark-to-market gains.

Current Period natural gas and oil property divestiture proceeds of $2.445 billion included approximately $744 million from our tenth VPP transaction, approximately $572 million from the sale of our Texoma Woodford assets, $376 million from the sale of the Midland Basin portion of our Permian Basin sale, $358 million for our non-core Utica Shale sale, $228 million of joint venture leasehold sales and approximately $167 million from other property sales.
Prior Period property divestiture proceeds of $6.357 billion included $4.310 billion from the sale of our Fayetteville assets, $570 million paid at the closing of our Niobrara Shale joint venture, $853 million from our ninth VPP transaction, $474 million of joint venture leasehold sales and $150 million from other property sales.
In June 2012, we sold all of our limited partner and general partner interests in ACMP to funds affiliated with GIP for cash proceeds of $2.0 billion. We recorded a $1.032 billion pre-tax gain associated with the transaction.
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 $13.986 billion and repaid $13.614 billion in the Current Period, and we borrowed $11.914 billion and repaid $12.057 billion in the Prior Period under our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. In September 2012, we completed our semi-annual collateral redetermination as required by the terms of the corporate revolving bank credit agreement. 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. Our revolving bank credit facilities are described below under Bank Credit Facilities.
In May 2012, we entered into unsecured term loans aggregating $4.0 billion. The net proceeds of the term loans, after customary fees and syndication costs, of approximately $3.789 billion were used to repay borrowings under our corporate revolving credit facility and for general corporate purposes. Subsequent to September 30, 2012, we used $4.0 billion in proceeds from asset sales and our new term loan (see Recent Developments) to fully repay the term loans without premium or penalty, as permitted by the terms of the loans. Our May 2012 term loan credit agreement is described below under Term Loans.
In February 2012, 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. At any time from and including November 15, 2012 to and including March 15, 2013, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount of the notes plus accrued and unpaid interest, if any, to the redemption date; provided that upon any redemption of the notes in part (and not in whole) pursuant to this redemption provision, at least $250 million aggregate principal amount of the notes remains outstanding.
During the Prior Period, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our corporate revolving bank credit facility.
During the Current Period, 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 in the existing wells and up to 1,000 new net wells to be drilled on certain of our Cleveland and Tonkawa play leasehold. CHK C-T is an unrestricted, non-guarantor consolidated subsidiary we formed in March 2012 to continue development of a portion of our Cleveland and Tonkawa plays covering Ellis and Roger Mills counties in western Oklahoma.
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. We paid $36 million in the Current Period and received $1.085 billion in the Prior Period for settlements of derivatives which were classified as cash flows from financing activities.

Uses of Funds

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under Investing Activities below, which sets forth the components of our natural gas and oil investing activities and our other investing activities for the Current Period and the Prior Period. As stated above in Capital Expenditures, we retain a significant degree of control over the timing of our capital expenditures, which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, changes in drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program.

We paid dividends on our common stock of $170 million and $151 million in the Current Period and the Prior Period, respectively. We paid dividends on our preferred stock of $128 million and $128 million in the Current Period and the Prior Period, respectively.

During the Current Period, we distributed $163 million in cash to certain of our noncontrolling interest owners.

During the Prior Period, we completed and settled tender offers to purchase the following senior notes and contingent convertible senior notes. We funded the purchase of the notes with a portion of the net proceeds we received from the sale of our Fayetteville Shale assets.

	Principal Amount Purchased ($ in millions)
7.625% senior notes due 2013	$36
9.5% senior notes due 2015	160
6.25% euro-denominated senior notes due 2017[(a)]	380
6.5% senior notes due 2017	440
6.875% senior notes due 2018	126
7.25% senior notes due 2018	131
6.625% senior notes due 2020	100
Total senior notes	1,373
2.75% contingent convertible senior notes due 2035	55
2.5% contingent convertible senior notes due 2037	210
2.25% contingent convertible senior notes due 2038	266
Total contingent convertible senior notes	531
Total	$1,904

(a) We purchased €256 million in aggregate principal amount of our euro-denominated senior notes which had a value of $380 million based on the exchange rate of $1.4821 to €1.00. Simultaneously with our purchase of the euro-denominated senior notes, we unwound cross currency swaps for the same principal amount. See Note 7 of the notes to our condensed consolidated financial statements included in Part I, Item 1 of this report for additional information.

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

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

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Investing Activities

Cash used in investing activities increased to $8.154 billion during the Current Period, compared to $3.715 billion during the Prior Period. The majority of the $4.439 billion increase in cash used in investing activities was the result of the sale of our Fayetteville Shale assets in the Prior Period. We made significant additions to our liquids-rich leasehold acreage in both the Current Period and the Prior Period, with acquisitions of unproved properties totaling $1.850 billion and $3.249 billion, respectively. Drilling and completion costs on proved and unproved properties increased $2.183 billion to $7.360 billion in the Current Period compared to $5.177 billion in the Prior Period. This increase is due to increased drilling activity and a reduction in drilling carries received. See Capital Expenditures for a description of our budgeted capital expenditures in 2012 and 2013. The following table shows our cash used in investing activities during the Current Period and the Prior Period:

	Nine Months Ended September 30,	
	2012	2011
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Drilling and completion costs [a]	$(7,360)	$(5,177)
Acquisitions of proved properties	(340)	(46)
Acquisitions of unproved properties	(1,850)	(3,249)
Proceeds from divestitures of proved and unproved properties	2,445	6,357
Geological and geophysical costs[b]	(165)	(168)
Interest capitalized on unproved properties	(623)	(478)
Total natural gas and oil investing activities	(7,893)	(2,761)
Other Investing Activities:		
Additions to other property and equipment	(1,916)	(1,416)
Proceeds from sales of other assets	219	682
Proceeds from (additions to) investments	(261)	126
Proceeds from sale of midstream investment	2,000	—
Acquisition of drilling company	—	(339)
Restricted Cash	(280)	—
Other	(23)	(7)
Total other investing activities	(261)	(954)
Total cash used in investing activities	$(8,154)	$(3,715)

(a) Net of $655 million and $1.868 billion in drilling and completion carry credits received from our joint venture partners during the Current Period and the Prior Period, respectively.

(b) Including related capitalized interest.

Bank Credit Facilities

During the Current Period, we used three revolving bank credit facilities as sources of liquidity. In June 2012, we paid off and terminated our midstream credit facility. Our two 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 September 30, 2012	$1,785	$336
Letters of credit outstanding as of September 30, 2012	$31	$—

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

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

Our corporate and oilfield services 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 the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. These margins may be increased pursuant to the terms of the recent 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.

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 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for further discussion. The amendment, among other things, adjusts our required indebtedness to EBITDA ratio covenant as set forth below through the earlier of (a) December 31, 2013 and (b) 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	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 borrowings 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 September 30, 2012.

Our actual indebtedness to EBITDA ratio as of September 30, 2012 was approximately 4.83 to 1.00. The ratio of indebtedness to EBITDA is calculated using non-GAAP financial measures that are defined in the credit facility agreement. The indebtedness to EBITDA ratio is calculated as the ratio of consolidated indebtedness to consolidated EBITDA for the 12-month period ending on the measurement date. Consolidated indebtedness is comprised of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA is comprised 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 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 our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

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 has initial availability 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, but they are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes 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 to EBITDAR, a senior secured leverage ratio based on a ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of EBITDAR to lease adjusted interest expense, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at September 30, 2012. 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 midstream 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 anticipated sale 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 18 counterparties that have committed to provide approximately 6.5 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.5 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.5 billion under the terms of the facility. As of September 30, 2012, we had hedged under the facility 1.4 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 these dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures and sale/leaseback arrangements. 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 derivative instruments. 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.

Term Loans

In May 2012, we entered into $4.0 billion of unsecured term loans under a credit agreement that provided for term loans in an aggregate principal amount of $4.0 billion. The net proceeds of the term loans of approximately $3.789 billion after discount, customary fees and syndication costs were used to repay borrowings under our corporate revolving credit facility and for general corporate purposes. The term loans were issued at a discount of 3%, or $120 million, and the customary fees and syndication costs incurred were approximately $91 million. Subsequent to September 30, 2012, we used proceeds from asset sales and our new term loan to fully repay the May 2012 term loans. We will record $155 million of associated losses with the repayment, including $86 million of deferred charges and $114 million of debt discount, offset by $45 million of interest accrued that will not be paid. Provisions that applied when the term loans were outstanding are described below.

Amounts borrowed under the term loan credit agreement bear interest, at our option, at either (a) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin (as described below) or (b) a base rate equal to the greater of (i) the prime rate quoted in the Wall Street Journal, (ii) the federal funds effective rate plus 0.50% per annum and (iii) 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. The Eurodollar rate is subject to a floor of 1.50% per annum and the base rate is subject to a floor of 2.50% per annum. Interest is payable quarterly or, if the Eurodollar rate applies, it may be payable at more frequent intervals. The initial applicable margin for Eurodollar loans is 7.0% per annum and the initial applicable margin for base rate loans is 6.0% per annum. If any amounts remain outstanding under the term loan credit agreement following January 1, 2013, the applicable margin under the term loan credit agreement will increase to 10.0% per annum for Eurodollar loans and to 9.0% per annum for base rate loans. Due to the escalating rate characteristic of the loan, we recognize interest expense using the interest method which, based on the current applicable interest rates, yields an 11.16% interest rate over the loan term. To the extent interest rates increase above the current applicable rates, the increase will be accounted for in the applicable period.

Amounts outstanding under the term loan credit agreement are unconditionally guaranteed on a joint and several basis by certain of the Company's direct and indirect wholly owned subsidiaries (including the subsidiaries that are subsidiary guarantors under our corporate revolving bank credit facility). The term loans are not secured by any assets of the Company or its subsidiaries.

The term loans, which rank equally in right of payment with our outstanding senior notes, mature on December 2, 2017 and may be repaid, in whole or in part, at any time in 2012 without premium or penalty. On and following January 1, 2013, we are required to pay a yield maintenance premium, equal to the present value of all interest payments that would have been made in respect of the principal of such loans from the date of such prepayment to maturity, in connection with any prepayment (including the prepayments described in the following paragraph) prior to December 2, 2017.

The 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 increase of dividends or payment of special dividends, investments in unrestricted subsidiaries and designations of subsidiaries as unrestricted subsidiaries. The term loan credit agreement also contains a covenant that requires that the net cash proceeds from certain asset dispositions and other asset sales, including assets of the Company or its subsidiaries in the Permian Basin in Texas and New Mexico, and certain financing transactions (subject to certain thresholds and exceptions) be used to either (a) prepay loans outstanding under the term loan credit agreement or (b) reduce the commitments and repay amounts outstanding under our corporate revolving bank credit facility (or, to the extent the proceeds exceed the commitments under the revolving facility, other senior debt). If, prior to January 1, 2013, we use such designated proceeds to repay amounts outstanding under our corporate revolving bank credit facility, then the applicable margin under the term loan credit agreement will increase to 8.0% per annum for Eurodollar loans and 7.0% per annum for base rate loans. The term loan credit agreement does not contain financial maintenance covenants.

We were in compliance with all covenants under the term loan credit agreement at September 30, 2012. If we should fail to perform our obligations under the agreement, the term loans 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.

On or after May 11, 2013, the lenders will have the option (subject to certain thresholds) to exchange their loans under the term loan credit agreement for fixed rate notes (Exchange Notes). The Exchange Notes will bear interest at a fixed annual rate of 11.50%, payable semi-annually, will mature on December 2, 2017, will not be subject to any sinking fund or amortization and will contain substantially the same call protection (in the form of a customary treasury rate plus 50 basis points bond make-whole), covenants and events of default as the loans under the term loan credit agreement. The Exchange Notes will rank equally in right of payment with the loans under the term loan credit agreement.

See Recent Developments above for a description of our newly established term loan. A portion of the net proceeds from this term loan was used to fully repay the May 2012 term loans.

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities and the term loans discussed above, our long-term debt consisted of the following as of September 30, 2012:

	September 30, 2012 ($ 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]	442
6.5% senior notes due 2017	660
6.875% senior notes due 2018	474
7.25% senior notes due 2018	669
6.625% senior notes due 2019[c]	650
6.775% senior notes due 2019	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[d]	396
2.5% contingent convertible senior notes due 2037[d]	1,168
2.25% contingent convertible senior notes due 2038[d]	347
Discount on senior notes[e]	(445)
Interest rate derivatives[f]	21
Total debt, net	10,211
Less current maturities of long-term debt[a]	(463)
Total long-term debt, net	$9,748

(a) These senior notes are due July 2013. There is $1 million of discount associated with these notes.

(b) The principal amount shown is based on the exchange rate of $1.2856 to €1.00 as of September 30, 2012. See Note 7 of our condensed consolidated financial statements included in 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) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder’s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarterly. In the third quarter of 2012, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the fourth quarter of 2012 under this provision. The notes are also convertible, at the holder’s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note’s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period in which contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$48.51	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	$107.27	June 14, 2019

(e) Included in this discount is $393 million at September 30, 2012 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(f) See Note 7 of our condensed consolidated financial statements included in this report for discussion related to these instruments.

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 wholly owned subsidiaries. Certain of our oilfield services subsidiaries, subsidiaries with noncontrolling interests, subsidiaries qualified as variable interest entities, and certain midstream and de minimis subsidiaries are not guarantors.

See Note 14 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries.

We may redeem the senior notes, other than the contingent convertible senior notes, at any time at specified make-whole or redemption prices. Our senior notes are governed by indentures containing covenants that 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% and 8%, respectively.

In July 2013, the $464 million aggregate principal amount of our 7.625% senior notes will be due. No other scheduled principal payments are required on our senior notes until 2015.

COO Senior Notes

In October 2011, our wholly owned subsidiaries, COO and COF, 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, 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 indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets. The COO senior notes

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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 within 365 days after the closing of the COO senior notes offering 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 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. We also agreed to make additional interest payments to holders, up to a maximum of 1% per annum, of the COO senior notes if we do not comply with our obligations under the registration rights agreement. We did not file a registration statement within 365 days after the closing of the COO senior notes and in the Current Quarter accrued approximately $1 million of additional expense we expect to incur related to this delay.

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. On September 30, 2012, our natural gas, oil and NGL and interest rate derivative instruments were spread among 16 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 the majority of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.164 billion at September 30, 2012) and exploration and production companies which own interests in properties we operate ($946 million at September 30, 2012). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Period and the Prior Period, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

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 September 30, 2012, these arrangements and transactions included (i) operating lease agreements, (ii) VPP obligations (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) variable interests held in VIEs 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 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 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 costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs. 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 in Part I, Item 1 of this report for further discussion of commitments, VPPs and VIEs, respectively.

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Results of Operations – Three Months Ended September 30, 2012 vs. September 30, 2011

General. For the Current Quarter, Chesapeake had a net loss of $1.971 billion, or $3.19 per diluted common share, on total revenues of $2.970 billion. This compares to net income of $922 million, or $1.23 per diluted common share, on total revenues of $3.977 billion during the Prior Quarter.

Natural Gas, Oil and NGL Sales. During the Current Quarter, natural gas, oil and NGL sales were $1.437 billion compared to $2.402 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced and sold 381.1 bcfe at a weighted average price of $4.04 per mcfe, compared to 306.2 bcfe produced and sold in the Prior Quarter at a weighted average price of $5.78 per mcfe (weighted average prices exclude the effect of unrealized losses on derivatives of $104 million and unrealized gains of $631 million in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenues of $662 million and increased production resulted in a $433 million increase, for a total decrease in revenues of $229 million (excluding unrealized gains or losses on natural gas, oil and NGL derivatives). The increase in production from the Prior Quarter to the Current Quarter was primarily generated through the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $1.97, compared to $4.82 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). In the Prior Quarter, realized prices of natural gas include gains related to swaps that had an above-market fixed price on the origination date. We obtained these above-market swaps by selling out-year call options on a portion of our projected natural gas and oil production. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $90.79 and $82.47 in the Current Quarter and Prior Quarter, respectively. NGL prices realized per barrel (excluding unrealized gains or losses on derivatives) were $31.22 and $41.16 in the Current Quarter and the Prior Quarter, respectively.

Realized gains or losses from our natural gas, oil and NGL derivatives resulted in a net increase in natural gas, oil and NGL revenues of $77 million, or $0.20 per mcfe, in the Current Quarter and a net increase of $344 million, or $1.12 per mcfe, in the Prior Quarter. See Part I, Item 3 of this report for a complete listing of all of our derivative instruments as of September 30, 2012.

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 $30 million and $29 million, respectively, 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 $13 million without considering the effect of hedging activities.

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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 September 30, 2012								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[(a)]	(mmbbl)	($/bbl)[(a)]	(mmbbl)	($/bbl)[(a)]	(bcfe)	%	($/mcfe)[(a)]
Southern[(b)]	166.7	1.67	0.4	93.96	0.3	28.48	171.2	46	1.91
Northern	53.0	2.18	3.8	86.70	2.3	31.55	89.3	23	5.76
Eastern	66.2	1.92	0.1	88.23	0.4	33.65	69.4	18	2.16
Western[(c)]	16.4	1.43	4.7	88.78	1.1	30.04	51.2	13	9.28
Total[(d)]	302.3	1.80	9.0	88.07	4.1	31.22	381.1	100 %	3.84

	Three Months Ended September 30, 2011								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[(a)]	(mmbbl)	($/bbl)[(a)]	(mmbbl)	($/bbl)[(a)]	(bcfe)	%	($/mcfe)[(a)]
Southern[(b)]	147.7	3.21	—	—	0.3	39.55	149.4	48	3.25
Northern	57.3	3.74	2.6	84.52	2.8	43.39	89.7	29	6.19
Eastern	35.2	3.54	0.1	74.50	0.4	54.99	38.1	14	4.02
Western	14.0	3.47	1.9	83.95	0.6	41.40	29.0	9	8.00
Total[(d)]	254.2	3.39	4.6	84.18	4.1	44.04	306.2	100 %	4.66

(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) 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 and NGL price realizations in the Current Quarter as a result of higher transportation costs compared to more developed plays.

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

Our average daily production of 4.142 bcfe for the Current Quarter consisted of 3.286 bcf of natural gas (79% on a natural gas equivalent basis) and approximately 142,675 bbls of liquids, consisting of approximately 97,785 bbls of oil (14% on a natural gas equivalent basis) and approximately 44,890 bbls of NGL (7% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 19% and our year-over-year growth rate of liquids production was 51%. Our percentage of revenues from liquids in the Current Quarter was 63% of unhedged natural gas, oil and NGL revenues compared to 40% in the Prior Quarter.

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 $1.381 billion in marketing, gathering and compression sales in the Current Quarter with corresponding expenses of $1.339 billion, for a net margin before depreciation of $42 million. This compares to sales of $1.422 billion, expenses of $1.392 billion and a net margin before depreciation of $30 million in the Prior Quarter. In the Current Quarter, the decrease in revenues and expenses is due primarily to lower natural gas prices and the sale of certain of our Appalachian midstream assets in December 2011, partially offset by an increase in volumes marketed. We plan to sell substantially all of our gathering assets in the 2012 fourth quarter which will have a future impact on our marketing, gathering and compression sales and expenses. Our gathering business provided for approximately $16 million and $17 million of the net margin above in the Current Quarter and 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 $152 million in oilfield services revenues in the Current Quarter with corresponding expenses of $116 million, for a net margin before depreciation of $36 million. This compares to revenue of $153 million, expenses of $118 million and a net margin before depreciation of $35 million in the Prior Quarter. Margin related to our contract drilling and tool and equipment rental businesses decreased as our operated rig count decreased throughout 2012. This was offset by an increase in margin in our hydraulic fracturing business as it became operational in the 2012 first quarter. Our oilfield services segment was also negatively impacted by impairments and early lease termination payments. See Losses on Sales and Impairments of Fixed Assets and Other for further discussion.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $320 million in the Current Quarter and $282 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.84 per mcfe in the Current Quarter compared to $0.92 per mcfe in the Prior Quarter. The per unit expense decrease in the Current Quarter was primarily the result of an overall decrease in field rates and increased production, offset by the lifting costs associated with VPP production for VPP #10 and #9 completed in March 2012 and May 2011, respectively. Production expenses in the Current Quarter and Prior Quarter included approximately $55 million and $59 million, or $0.14 and $0.19 per mcfe, respectively, associated with VPP production volumes.

Production Taxes. Production taxes were $53 million in the Current Quarter compared to $50 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.14 per mcfe in the Current Quarter compared to $0.16 per mcfe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. The $3 million increase in production taxes in the Current Quarter was primarily due to an increase in production of 75 bcfe. Production taxes in the Current Quarter and Prior Quarter included approximately $5 million and $9 million, or $0.01 and $0.03 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 $148 million in the Current Quarter compared to $151 million in the Prior Quarter. General and administrative expenses were $0.39 and $0.49 per mcfe for the Current Quarter and Prior Quarter, respectively. The per unit expense decrease was primarily due to an increase in production of 75 bcfe. Included in general and administrative expenses is stock-based compensation of $17 million for the Current Quarter and $24 million for the Prior Quarter. Restricted stock expense is based on the price of our common stock on the grant date of the award.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. Employee restricted stock awards generally vest over a period of four years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 6 of our condensed consolidated financial statements included in Part I, Item 1 of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, divestiture, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, divestiture, 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 $112 million and $116 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas

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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 $762 million and $423 million during the Current Quarter and the Prior Quarter, respectively. The $339 million increase is primarily the result of a 24% increase in production from the Prior Quarter compared to the Current Quarter, the decrease in Barnett Shale and Haynesville Shale proved undeveloped reserves primarily as a result of downward price revisions, and the higher 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 $2.00 and $1.38 in the Current Quarter and the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $66 million in the Current Quarter and $75 million in the Prior Quarter. Depreciation and amortization of other assets was $0.17 million and $0.24 per mcfe for the Current Quarter and the Prior Quarter, respectively. The decrease in the Current Quarter is primarily due to the reclassification of approximately $2.2 billion of property and equipment to held for sale as of June 30, 2012. Assets classified as held for sale are not subject to depreciation. See Note 1 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for information regarding our assets held for sale. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to twenty years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as drilling and completion costs.

Impairment of Natural Gas and Oil Properties. In the Current Quarter, we reported a non-cash impairment charge on our natural gas and oil properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012 compared to June 30, 2012, and the impairment of certain undeveloped leasehold, primarily in the Williston and DJ Basins. We account for our natural gas and oil properties using the full cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on pricing and cost assumptions prescribed by the SEC and the present value of certain natural gas and oil derivative instruments. See Note 11 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for further discussion of our impairment of natural gas and oil properties.

Losses on Sales and Impairments of Fixed Assets and Other. In the Current Quarter, losses on sales and impairments of fixed assets and other were $45 million compared to $3 million in the Prior Quarter. In the Current Quarter, we recorded impairments of $13 million consisting of $7 million related to surface land and $6 million related to certain drilling rigs. In addition, we recorded a charge of $25 million related to early lease termination costs, and we recorded $7 million of losses on sales of fixed assets. In the Prior Quarter, we recorded $3 million of losses on sales of drilling rigs, pipe, gas gathering systems and other miscellaneous fixed assets. See Note 11 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for further discussion of our losses on sales and impairments of fixed assets and other.

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Interest Expense. Interest expense was $36 million in the Current Quarter compared to $4 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2012	2011
	($ in millions)	
Interest expense on senior notes	$187	$152
Interest expense on credit facilities	13	18
Interest expense on term loans	112	—
Unrealized (gains) losses on interest rate derivatives	(2)	—
Amortization of loan discount, issuance costs and other	24	8
Capitalized interest	(298)	(174)
Total interest expense	$36	$4
Average long-term borrowings	$14,257	$8,700

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.10 per mcfe in the Current Quarter compared to $0.01 per mcfe in the Prior Quarter.

Earnings (Losses) on Investments. Losses on investments were $23 million in the Current Quarter compared to earnings on investments of $28 million in the Prior Quarter, primarily as result of our equity in the net income (loss) of certain investments.

Gains on Sales of Investments. In the Current Quarter, we sold 50% of our investment in Glass Mountain Pipeline, LLC for cash proceeds of $47 million. We recorded a $31 million gain associated with the transaction.

Other Income (Expense). We recorded $9 million of other expense in the Current Quarter compared to $4 million of other income in the Prior Quarter.

Income Taxes. Chesapeake recorded an income tax benefit of $1.260 billion in the Current Quarter compared to income tax expense of $589 million in the Prior Quarter. Our effective income tax rate was 39% in both the Current Quarter and the Prior Quarter. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. In connection with the audit of our 2008 and 2009 returns, the IRS reviewed certain issues with respect to the FWPP. These issues were successfully resolved with no material impact to the Company.

Net Income Attributable to Noncontrolling Interests. In the Current Quarter, Chesapeake recorded $41 million of net income attributable to noncontrolling interests related to third-party ownership in CHK Utica, CHK C-T, the Chesapeake Granite Wash Trust and Cardinal Gas Services, L.L.C., all of which were formed in the fourth quarter of 2011 or the first quarter of 2012. There was no net income attributable to noncontrolling interests in the Prior Quarter.

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Results of Operations – Nine Months Ended September 30, 2012 vs. September 30, 2011

General. For the Current Period, Chesapeake had a net loss of $938 million, or $1.86 per diluted common share, on total revenues of $8.778 billion. This compares to net income of $1.269 billion, or 1.69 per diluted common share, on total revenues of $8.908 billion for the Prior Period.

Natural Gas, Oil and NGL Sales. During the Current Period, natural gas, oil and NGL sales were $4.622 billion compared to $4.688 billion in the Prior Period. In the Current Period, Chesapeake produced and sold 1.061 tcfe at a weighted average price of $3.95 per mcfe, compared to 863.3 bcfe produced and sold in the Prior Period at a weighted average price of $5.94 per mcfe (weighted average prices exclude the effect of unrealized gains on derivatives of $436 million and unrealized losses on derivatives of $444 million in the Current Period and the Prior Period, respectively). In the Current Period, the decrease in prices resulted in a decrease in revenues of $2.118 billion and increased production resulted in a $1.172 billion increase, for a total decrease in revenues of $946 million (excluding unrealized gains or losses on natural gas, oil and NGL derivatives). The increase in production from the Prior Period to the Current Period was primarily generated through the drillbit.

For the Current Period, we realized an average price per mcf of natural gas of $2.06, compared to $5.10 in the Prior Period (weighted average prices exclude the effect of unrealized gains or losses on derivatives). In the Prior Period, realized prices of natural gas included gains related to swaps that had an above-market fixed price on the origination date. We obtained these above-market swaps by selling out-year call options on a portion of our projected natural gas and oil production. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $91.55 and $85.45 in the Current Period and Prior Period, respectively. NGL prices realized per barrel (excluding unrealized gains or losses on derivatives) were $30.17 and $39.10 in the Current Period and the Prior Period, respectively.

Realized gains or losses from our natural gas, oil and NGL derivatives resulted in a net increase in natural gas, oil and NGL revenues of $388 million, or $0.37 per mcfe, in the Current Period and a net increase of $1.240 billion, or $1.43 per mcfe, in the Prior Period. See Part I, Item 3 of this report for a complete listing of all of our derivative instruments as of September 30, 2012.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming the Current Period production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $85 million and $82 million, respectively, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $35 million and $34 million, respectively, without considering the effect of hedging activities.

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The following tables show our production and average sales prices received by operating division for the Current Period and the Prior Period:

	Nine Months Ended September 30, 2012								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	468.5	1.44	1.4	95.91	1.1	29.64	483.9	46	1.75
Northern	156.8	2.01	10.4	90.69	8.0	29.12	267.0	25	5.57
Eastern	181.1	1.71	0.2	80.22	1.2	41.98	189.5	18	1.99
Western[c]	42.1	1.35	10.3	91.56	2.7	31.52	120.0	11	9.03
Total[d]	848.5	1.60	22.3	91.30	13.0	30.86	1,060.4	100 %	3.58

	Nine Months Ended September 30, 2011								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	392.3	3.00	—	—	0.7	35.94	397.1	46	3.05
Northern	205.3	3.65	7.3	90.39	7.6	41.59	294.4	34	5.84
Eastern	93.3	3.56	0.2	80.23	0.8	54.66	99.2	12	3.95
Western	41.0	3.73	4.2	88.90	1.1	40.34	72.6	8	7.81
Total[d]	731.9	3.30	11.7	89.78	10.2	42.17	863.3	100 %	4.51

(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) 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 and NGL price realizations in the Current Period as a result of higher transportation costs compared to more developed plays.

(d) The Current Period and the Prior Period production reflects the sale of all of our Fayetteville Shale assets, which closed in March 2011 and various other asset sales. See Note 8 of the notes to our condensed consolidated financial statements included in Part I, Item 1 of this report for information on divestitures. In addition, we curtailed our production of natural gas in the Current Period. See discussion below.

We curtailed our production of natural gas in the Current Period, beginning in February, because of low natural gas prices. Curtailed natural gas volumes in the Current Period averaged approximately 220 mmcf per day net to Chesapeake compared to no curtailments in the Prior Period. The curtailed volumes were located primarily in the Haynesville and Barnett shale plays. We ended our natural gas production curtailment program at the end of the second quarter of 2012. As a result of reduced drilling activity planned for 2012 and 2013 in our dry natural gas plays, we are projecting a decline in our natural gas production of 7% in 2013.

Our average daily production of 3.870 bcfe for the Current Period consisted of 3.097 bcf of natural gas (80% on a natural gas equivalent basis) and approximately 128,870 bbls of liquids, consisting of approximately 81,495 bbls of oil (13% on a natural gas equivalent basis) and approximately 47,375 bbls of NGL (7% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 16% and our year-over-year growth rate of liquids production was 61%. Our percentage of revenues from liquids in the Current Period was 64% of unhedged natural gas, oil and NGL revenues compared to 38% in the Prior Period.

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression sales and expenses consist of third-party revenue and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake primarily for owners in Chesapeake-operated wells. Chesapeake recognized $3.710 billion in marketing, gathering and compression sales in the Current Period with corresponding expenses of $3.631 billion, for a net margin before depreciation of $79 million. This compares to sales of $3.844 billion, expenses of $3.744 billion and a net margin before depreciation of $100 million in the Prior Period. In the Current Period, the decrease in revenues and expenses is due primarily to lower natural gas prices and the sale of certain of our Appalachian midstream assets in December 2011, partially offset by an increase in volumes marketed. In addition, we realized lower margins per mcfe during the Current Period primarily as a result of certain marketing arrangements whereby we resold natural gas and NGL at marginally lower market prices as compared to the contract price purchases of the natural gas and NGL. We plan to sell substantially all of our gathering assets in the 2012 fourth quarter which will have a future impact on our marketing, gathering and compression sales and expenses. Our gathering business provided for approximately $37 million and $35 million of the net margin above in the Current Period and Prior Period, respectively.

Oilfield Services Revenues and Expenses. Oilfield services consist of third-party revenue and expenses related to our oilfield services operations. Chesapeake recognized $446 million in oilfield services revenues in the Current Period with corresponding expenses of $321 million, for a net margin before depreciation of $125 million. This compares to revenue of $376 million, expenses of $287 million and a net margin before depreciation of $89 million in the Prior Period. Oilfield services revenues, expenses and margins have increased as our oilfield services business has grown. Our oilfield services segment was also negatively impacted by impairments and early lease termination payments. See Losses on Sales and Impairments of Fixed Assets and Other for further discussion.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $1.005 billion in the Current Period and $782 million in the Prior Period. On a unit-of-production basis, production expenses were $0.95 per mcfe in the Current Period compared to $0.91 per mcfe in the Prior Period. The per unit expense increase in the Current Period was primarily the result of a new fee retroactively imposed in Pennsylvania on spud wells, which had a $17 million, or $0.02 per mcfe effect, in addition to an overall increase in field rates and the lifting costs associated with VPP production for VPP #10 and #9 completed in March 2012 and May 2011, respectively. Production expenses in the Current Period and Prior Period included approximately $172 million and $169 million, or $0.16 and $0.20 per mcfe, respectively, associated with VPP production volumes.

Production Taxes. Production taxes were $141 million in the Current Period compared to $140 million in the Prior Period. On a unit-of-production basis, production taxes were $0.13 per mcfe in the Current Period compared to $0.16 per mcfe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. The $1 million increase in production taxes in the Current Period was primarily due to an increase in production of 197 bcfe. Production taxes in the Current Period and Prior Period included approximately $15 million and $15 million, or $0.01 and $0.02 per mcfe, respectively, associated with Current Period and Prior Period 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 $440 million in the Current Period and $410 million in the Prior Period. General and administrative expenses were $0.41 and $0.47 per mcfe for the Current Period and Prior Period, respectively. The $30 million increase in the Current Period compared to the Prior Period is primarily due to $25 million of additional legal costs incurred in the Current Period. The per unit expense decrease was primarily due to an increase in production of 197 bcfe. Included in general and administrative expenses is stock-based compensation of $55 million for the Current Period and $71 million for the Prior Period. Restricted stock expense is based on the price of our common stock on the grant date of the award.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. Employee restricted stock awards generally vest over a period of four years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 6 of our condensed consolidated financial statements included in Part I, Item 1 of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full cost method of accounting under which all costs associated with natural gas and oil property acquisition, divestiture, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, divestiture, 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 $346 million and $327 million of internal costs in the Current Period and the Prior Period, 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 and oil properties was $1.856 billion and $1.147 billion during the Current Period and the Prior Period, respectively. The $709 million increase is primarily the result of a 23% increase in production from the Prior Period compared to the Current Period, the decrease in Barnett Shale and Haynesville Shale proved undeveloped reserves primarily as a result of downward price revisions, and the higher 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 $1.75 and $1.33 in the Current Period and the Prior Period, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $233 million in the Current Period and $206 million in the Prior Period. Depreciation and amortization of other assets was $0.22 and $0.24 per mcfe for the Current Period and the Prior Period, respectively. The increase in the Current Period is primarily due to additional depreciation expense associated with assets acquired over the past year, offset by assets sold over the past year and assets reclassified as held for sale as of June 30, 2012. Assets classified as held for sale are not subject to depreciation. See Note 1 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for information regarding our assets held for sale. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to twenty years. To the extent company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as drilling and completion costs.

Impairment of Natural Gas and Oil Properties. In the Current Period, we reported a non-cash impairment charge on our natural gas and oil properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012 compared to June 30, 2012, and the impairment of certain undeveloped leasehold, primarily in the Williston and DJ Basins. We account for our natural gas and oil properties using the full cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves using a 10% pre-tax discount rate based on pricing and cost assumptions prescribed by the SEC and the present value of certain natural gas and oil derivative instruments. See Note 11 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for further discussion of our impairment of natural gas and oil properties.

Losses on Sales and Impairments of Fixed Assets and Other. In the Current Period, losses on sales and impairments of fixed assets and other were $286 million compared to $7 million in the Prior Period. In the Current Period, we recorded impairments of $281 million consisting of $227 million related to surface land and an office building located in our Barnett Shale operating area, $20 million related to certain drilling rigs and $9 million related to drill pipe. In addition, we recorded a charge of $25 million related to early lease termination costs and $5 million of losses on sales of other fixed assets. In the Prior Period, we recorded $4 million of impairments for certain fixed assets and $3 million of losses on sales of other fixed assets. See Note 11 of the notes to our condensed consolidated financial statements in Part 1, Item 1 of this report for further discussion of our losses on sales or impairments of fixed assets and other.

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Interest Expense. Interest expense was $63 million in the Current Period compared to $37 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2012	2011
	($ in millions)	
Interest expense on senior notes	$546	$494
Interest expense on credit facilities	51	49
Interest expense on term loans	173	—
Realized (gains) losses on interest rate derivatives	—	6
Unrealized (gains) losses on interest rate derivatives	(4)	13
Amortization of loan discount and other	67	30
Capitalized interest	(770)	(555)
Total interest expense	$63	$37
Average long-term borrowings	$12,373	$9,445

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.06 per mcfe in the Current Period and $0.03 per mcfe in the Prior Period.

Earnings (Losses) on Investments. In the Current Period, losses on investments were $87 million and in the Prior Period earnings on investments were $100 million, respectively, primarily as result of our equity in the net income (loss) of certain investments.

Gains on Sales of Investments. In the Current Period, we sold all of our common and subordinated units representing limited partner interests in Chesapeake Midstream Partners, L.P., now named Access Midstream Partners, L.P. (NYSE:ACMP), and all of our limited liability company interests in the sole member of its general partner to funds affiliated with Global Infrastructure Partners for cash proceeds of $2.0 billion. We recorded a $1.032 billion gain associated with the transaction. Also in the Current Period, we sold 50% of our investment in Glass Mountain Pipeline, LLC for cash proceeds of $47 million. We recorded a $31 million gain associated with the transaction.

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

Other Income. Other income was $2 million in the Current Period and $9 million in the Prior Period.

Income Taxes. Chesapeake recorded an income tax benefit of $599 million in the Current Period compared to income tax expense of $812 million in the Prior Period. Our effective income tax rate was 39% in both the Current Period and the Prior Period. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. Chesapeake's federal and state income tax returns are routinely audited by federal and state fiscal authorities. The Internal Revenue Service (IRS) is currently auditing our federal income tax returns for 2007 through 2011. In connection with the audit of our 2008 and 2009 returns, the IRS reviewed certain issues with respect to the FWPP. These issues were successfully resolved with no material impact to the Company.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $131 million in the Current Period related to third-party ownership in CHK Utica, CHK C-T, the Chesapeake Granite Wash Trust and Cardinal Gas Services, L.L.C., all of which were formed in the fourth quarter of 2011 or the first quarter of 2012. There was no net income attributable to noncontrolling interests in the Prior Period.

Application of Critical Accounting Policies

We consider accounting policies related to derivatives, variable interest entities, natural gas and oil properties and income taxes to be critical policies. These policies are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2011 Form 10-K.

Recently Issued and Proposed Accounting Standards

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

In December 2011, the FASB issued guidance on disclosure of information about offsetting and related arrangements to enable users of a company's financial statements to understand the effect of those arrangements on its financial position. The standard is effective for annual reporting periods beginning on or after January 1, 2013. This guidance will not have an impact on our financial position or results of operations.

In June 2011, the FASB issued guidance on comprehensive income, which provides two options for presenting items of net income, comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements. We adopted this guidance in 2011. Adoption had no impact on our financial position or results of operations. In December 2011, the FASB deferred the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income. This guidance will not have an impact on our financial position or results of operations.

In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements which expands existing fair value disclosure requirements, particularly for Level 3 inputs. The new requirements include quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs; and the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed. The guidance was effective for interim and annual periods beginning on or after December 15, 2011. Adoption had no impact on our financial position or results of operations.

Forward-Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Forward-looking statements give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas, 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 and 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. 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, reduce our indebtedness as planned and maintain our compliance with revolving bank credit agreement covenants could be adversely affected. 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 2011 Form 10-K. They 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 values of our natural gas and oil properties resulting in ceiling test write-downs;
- the availability of capital on an economic basis, including planned sales, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;
- leasehold terms expiring before production can be established;
- hedging activities resulting in lower prices realized on natural gas, oil and NGL sales and the need to secure hedging liabilities;
- drilling and operating risks, including potential environmental liabilities;
- changes in legislation and regulation adversely affecting our industry and our business;
- general economic conditions negatively impacting us and our business counterparties;
- oilfield services shortages, pipeline and gathering system capacity constraints and transportation interruptions that could adversely affect our cash flow; and
- losses possible from pending or future litigation.

We caution you not to place undue reliance on 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 the exposure to adverse market 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 hedged 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 allow us to generate high cash margins and when we view prices to be in the upper range of our predicted future price range. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps and options (calls 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 the Current Period, 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. In the fourth quarter of 2011, we entered into oil swaps that can be extended at the option of the counterparty. This allows us to receive a higher fixed price on these swaps than what the market would have offered without such an option. 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 estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production (risked) from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not hedge more volumes than we expect to produce, and if production estimates are lowered for future periods and 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 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.

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We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are 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 12 of the notes to our consolidated financial statements in Part I, Item 1 of this report for further discussion of the fair value measurements associated with our derivatives.

As of September 30, 2012, our natural gas, oil and NGL derivative instruments consisted of the following:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Call Options: Chesapeake sells, 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. Chesapeake also buys put swaptions, that are exercisable on a specific date, which allows us to enter into a swap at a fixed price for a certain period of time.
- Basis protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. Our 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.

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As of September 30, 2012, we had the following open natural gas, oil and NGL derivative instruments:

	Volume (tbtu)	Weighted Average Price Fixed	Call (per mmbtu)	Differential	Designated Hedge	Fair Value ($ in millions)
Natural Gas:						
Swaps:						
Q4 2012	204	$3.04	$—	$—	No	$(58)
Call Options (sold):						
Q4 2012	67	—	6.05	—	No	(8)
Q1 2013	66	—	6.39	—	No	—
Q2 2013	67	—	6.39	—	No	(1)
Q3 2013	68	—	6.39	—	No	(1)
Q4 2013	68	—	6.39	—	No	(3)
2014	330	—	6.43	—	No	(28)
2015	227	—	6.31	—	No	(40)
2016	279	—	6.72	—	No	(78)
2017 – 2020	114	—	10.92	—	No	(19)
Call Options (bought)[(a)]:						
Q4 2012	(41)	—	7.90	—	No	—
Q1 2013	(66)	—	6.39	—	No	(3)
Q2 2013	(67)	—	6.39	—	No	(2)
Q3 2013	(68)	—	6.39	—	No	(1)
Q4 2013	(68)	—	6.39	—	No	—
2014	(330)	—	6.43	—	No	(13)
2015	(110)	—	6.16	—	No	(40)
2016	(44)	—	6.00	—	No	(13)
Basis Protection Swaps:						
Q4 2012	8	—	—	(0.74)	No	(4)
2013	44	—	—	(0.21)	No	(1)
2014	28	—	—	(0.32)	No	(3)
2015	31	—	—	(0.34)	No	(3)
2016 – 2022	8	—	—	(1.02)	No	(6)
Put Swaptions (bought)[(b)]:						
2013	11	3.75	—	—	No	(1)
Total Natural Gas						$(326)

	Volume (mmbbl)	Weighted Average Price Fixed	Call (per bbl)	Differential	Designated Hedge	Fair Value ($ in millions)
Oil:						
Swaps:						
Q4 2012	6.2	$99.14	$—	$—	No	$40
Q1 2013	5.6	95.95	—	—	No	12
Q2 2013	6.7	96.09	—	—	No	13
Q3 2013	6.7	96.02	—	—	No	15
Q4 2013	6.7	95.97	—	—	No	18
2014 – 2015	1.4	90.11	—	—	No	(1)
Call Options (sold)(c):						
Q4 2012	2.1	—	100.00	—	No	(2)
Q1 2013	4.8	—	94.74	—	No	(34)
Q2 2013	4.8	—	94.74	—	No	(44)
Q3 2013	4.9	—	94.74	—	No	(49)
Q4 2013	4.9	—	94.74	—	No	(51)
2014	16.9	—	96.92	—	No	(164)
2015	24.7	—	100.45	—	No	(227)
2016	18.9	—	104.71	—	No	(158)
2017	5.3	—	83.50	—	No	(87)
Call Options (bought)(d):						
Q4 2012	(1.6)	—	100.00	—	No	2
Q1 2013	(2.3)	—	90.80	—	No	2
Q2 2013	(2.3)	—	90.80	—	No	6
Q3 2013	(2.4)	—	90.80	—	No	8
Q4 2013	(2.3)	—	90.80	—	No	9
2014	(2.2)	—	94.91	—	No	4
Call Swaptions (sold):						
Q1 2013	0.9	102.85	—	—	No	(2)
Q2 2013	0.9	102.85	—	—	No	(1)
Q3 2013	0.5	100.00	—	—	No	(1)
Q4 2013	0.4	100.00	—	—	No	(1)
2014	2.9	106.69	—	—	No	(11)
2015	2.4	106.61	—	—	No	(4)
	Total Oil					$(708)
	Total Natural Gas and Oil					$(1,034)

(a) Included in the fair value are deferred premiums of $11 million, $41 million, $61 million and $28 million which we will realize in 2013, 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $3 million which we will realize in 2013.

(c) Included in oil call options are NGL call options in the amount of 5,000 bbls per day at $38.01 per bbl for 2012.

(d) Included in the fair value are deferred premiums of $81 million and $19 million which we will realize in 2013 and 2014, respectively.

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In addition to the open derivative positions disclosed above, at September 30, 2012, we had $154 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.

	September 30, 2012
	($ in millions)
Q4 2012	(16)
Q1 2013	15
Q2 2013	35
Q3 2013	31
Q4 2013	22
2014	(164)
2015	216
2016 – 2022	15
Total	$154

The table below reconciles the changes in fair value of our natural gas, oil and NGL derivatives during the Current Period. Of the $1.034 billion fair value liability as of September 30, 2012, $118 million related to contracts maturing in the next 12 months and $916 million related to contracts maturing after 12 months. All open derivative instruments as of September 30, 2012 are expected to mature by December 31, 2022.

	2012
	($ in millions)
Fair value of contracts outstanding, as of January 1	$(1,639)
Change in fair value of contracts	640
Fair value of new contracts when entered into	90
Contracts realized or otherwise settled	(94)
Fair value of contracts when closed	(31)
Fair value of contracts outstanding, as of September 30	$(1,034)

The change in natural gas, oil and NGL prices during the Current Period decreased the liability of our derivative instruments by $640 million. This gain is recorded in natural gas, oil and NGL sales. We entered into new contracts which were in an asset position of $90 million. We settled contracts that were in an asset position for $94 million and we closed out contracts that were in an asset position for $31 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 September 30, 2012, we did not have any natural gas, oil and NGL derivatives that were designated as cash flow hedges.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	($ in millions)			
Natural gas, oil and NGL sales	$1,464	$1,427	$3,798	$3,892
Realized gains (losses) on natural gas, oil and NGL derivatives	77	344	388	1,240
Unrealized gains (losses) on natural gas, oil and NGL derivatives	(104)	636	436	(457)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	—	(5)		