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laims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, several mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas 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 believes that it has substantial defenses to the claims made in these purchase and sale cases. The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management s estimates.

There are pending against us enforcement actions initiated in the 2010 fourth quarter and 2011 first quarter by the Pennsylvania Department of Environmental Protection related to alleged methane migration into the groundwater and residential water wells and by the U.S. Environmental Protection Agency related to our compliance with Clean Water Act permitting requirements in West Virginia. We have responded to all pending orders and are actively cooperating with the relevant agencies. While we cannot predict with certainty whether these actions will result in fines or penalties, if fines or penalties are imposed, we reasonably believe that each of these actions would result in monetary sanctions exceeding $100,000.

ITEM 4. ***Reserved***

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Part II

ITEM 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Price Range of Common Stock and Dividends

Our common stock trades on the New York Stock Exchange under the symbol CHK . The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange and the amount of cash dividends declared per share:

	Common Stock High	Common Stock Low	Dividend Declared
Year ended December 31, 2010:			
Fourth Quarter	$ 26.15	$ 21.12	$ 0.075
Third Quarter	$ 22.65	$ 20.04	$ 0.075
Second Quarter	$ 25.36	$ 20.75	$ 0.075
First Quarter	$ 28.97	$ 22.37	$ 0.075
Year ended December 31, 2009:			
Fourth Quarter	$ 30.00	$ 22.06	$ 0.075
Third Quarter	$ 29.49	$ 16.92	$ 0.075
Second Quarter	$ 24.66	$ 16.43	$ 0.075
First Quarter	$ 20.13	$ 13.27	$ 0.075

At February 24, 2011, there were approximately 2,050 holders of record of our common stock and approximately 398,250 beneficial owners.

While we expect to continue to pay dividends on our common stock, the payment of future cash dividends is subject to the discretion of our Board of Directors and will depend upon, among other things, our financial condition, our funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and other factors considered relevant by the Board of Directors.

In addition, our corporate revolving bank credit facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred. The certificates of designation for our preferred stock prohibit payment of cash dividends on our common stock unless we have declared and paid (or set apart for payment) full accumulated dividends on the preferred stock.

Purchases of Common Stock

The following table presents information about repurchases of our common stock during the three months ended December 31, 2010:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share[(a)]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
October 1, 2010 through October 31, 2010	206,562	$ 21.90		
November 1, 2010 through November 30, 2010	8,331	$ 21.37		
December 1, 2010 through December 31, 2010	12,909	$ 25.92		

Total	227,802	$	23.06

(a) Represents the deemed surrender to the company of 4,389 shares of common stock to pay the exercise price and withholding taxes in connection with the exercise of employee stock options and the surrender to the company of 223,413 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and deferred compensation plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for the purposes of the company contributions. There are no other repurchase plans or programs currently authorized by the Board of Directors.

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ITEM 6. ***Selected Financial Data***

The following table sets forth selected consolidated financial data of Chesapeake for the years ended December 31, 2010, 2009, 2008, 2007 and 2006. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. The table should be read in conjunction with *Management s Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements, including the notes, appearing in Items 7 and 8 of this report.

	Years Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
STATEMENT OF OPERATIONS DATA:	($ in millions, except per share data)				
REVENUES:					
Natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858	$ 5,624	$ 5,619
Marketing, gathering and compression sales	3,479	2,463	3,598	2,040	1,577
Service operations revenue	240	190	173	136	130
Total revenues	9,366	7,702	11,629	7,800	7,326
OPERATING COSTS:					
Production expenses	893	876	889	640	490
Production taxes	157	107	284	216	176
General and administrative expenses	453	349	377	243	139
Marketing, gathering and compression expenses	3,352	2,316	3,505	1,969	1,522
Service operations expense	208	182	143	94	68
Natural gas and oil depreciation, depletion and amortization	1,394	1,371	1,970	1,835	1,359
Depreciation and amortization of other assets	220	244	174	153	103
Impairment of natural gas and oil properties		11,000	2,800		
(Gains) losses on sales of other property and equipment	(137)	38			
Other impairments	21	130	30		
Restructuring costs		34			
Employee retirement expense					55
Total Operating Costs	6,561	16,647	10,172	5,150	3,912
INCOME (LOSS) FROM OPERATIONS	2,805	(8,945)	1,457	2,650	3,414
OTHER INCOME (EXPENSE):					
Interest expense	(19)	(113)	(271)	(401)	(316)
Earnings (losses) from equity investees	227	(39)	(38)		10
Losses on redemptions or exchanges of debt	(129)	(40)	(4)		
Impairment of investments	(16)	(162)	(180)		
Gain on sale of investments				83	117
Other income	16	11	27	15	16
Total Other Income (Expense)	79	(343)	(466)	(303)	(173)
INCOME (LOSS) BEFORE INCOME TAXES	2,884	(9,288)	991	2,347	3,241
INCOME TAX EXPENSE (BENEFIT):					
Current income taxes		4	423	29	5
Deferred income taxes	1,110	(3,487)	(36)	863	1,242
Total Income Tax Expense (Benefit)	1,110	(3,483)	387	892	1,247

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	Years Ended December 31,				
	2010	2009	2008	2007	2006
STATEMENT OF OPERATIONS DATA (continued):	($ in millions, except per share data)				
NET INCOME (LOSS)	1,774	(5,805)	604	1,455	1,994
Net (income) loss attributable to noncontrolling interest		(25)			
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,774	(5,830)	604	1,455	1,994
Preferred stock dividends	(111)	(23)	(33)	(94)	(89)
Loss on conversion/exchange of preferred stock			(67)	(128)	(10)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,663	$ (5,853)	$ 504	$ 1,233	$ 1,895
EARNINGS (LOSS) PER COMMON SHARE:					
Basic	$ 2.63	$ (9.57)	$ 0.94	$ 2.70	$ 4.76
Assuming dilution	$ 2.51	$ (9.57)	$ 0.93	$ 2.63	$ 4.33
CASH DIVIDENDS DECLARED PER COMMON SHARE	$ 0.30	$ 0.30	$ 0.2925	$ 0.2625	$ 0.23
CASH FLOW DATA:					
Cash provided by operating activities	$ 5,117	$ 4,356	$ 5,357	$ 4,974	$ 4,843
Cash used in investing activities	$ 8,503	$ 5,462	$ 9,965	$ 7,964	$ 8,942
Cash provided by (used in) financing activities	$ 3,181	$ (336)	$ 6,356	$ 2,988	$ 4,042
BALANCE SHEET DATA (AT END OF PERIOD):					
Total assets	$ 37,179	$ 29,914	$ 38,593	$ 30,764	$ 24,413
Long-term debt, net of current maturities	$ 12,640	$ 12,295	$ 13,175	$ 10,178	$ 7,187
Total equity	$ 15,264	$ 12,341	$ 17,017	$ 12,624	$ 11,366

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ITEM 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***
Financial Data

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the periods indicated:

	Years Ended December 31,		
	2010	**2009**	**2008**
Net Production:			
Natural gas (bcf)	924.9	834.8	775.4
Oil (mmbbl)[(a)]	18.4	11.8	11.2
Natural gas equivalent (bcfe)	1,035.2	905.5	842.7
Natural Gas and Oil Sales ($ in millions):			
Natural gas sales	$ 3,169	$ 2,635	$ 6,003
Natural gas derivatives realized gains (losses)	1,982	2,313	267
Natural gas derivatives unrealized gains (losses)	425	(492)	521
Total natural gas sales	5,576	4,456	6,791
Oil sales[(a)]	1,079	656	1,066
Oil derivatives realized gains (losses)	74	33	(275)
Oil derivatives unrealized gains (losses)	(1,082)	(96)	276
Total oil sales	71	593	1,067
Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858
Average Sales Price (excluding gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 3.43	$ 3.16	$ 7.74
Oil ($ per bbl)	$ 58.67	$ 55.60	$ 95.04
Natural gas equivalent ($ per mcfe)	$ 4.10	$ 3.63	$ 8.39
Average Sales Price (excluding unrealized gains (losses) on derivatives):			
Natural gas ($ per mcf)	$ 5.57	$ 5.93	$ 8.09
Oil ($ per bbl)	$ 62.71	$ 58.38	$ 70.48
Natural gas equivalent ($ per mcfe)	$ 6.09	$ 6.22	$ 8.38
Other Operating Income[(b)] ($ in millions):			
Marketing, gathering and compression net margin	$ 127	$ 147	$ 93
Service operations net margin	$ 32	$ 8	$ 30
Other Operating Income[(b)] ($ per mcfe):			
Marketing, gathering and compression net margin	$ 0.12	$ 0.16	$ 0.11
Service operations net margin	$ 0.03	$ 0.01	$ 0.04
Expenses ($ per mcfe):			
Production expenses	$ 0.86	$ 0.97	$ 1.05
Production taxes	$ 0.15	$ 0.12	$ 0.34
General and administrative expenses	$ 0.44	$ 0.38	$ 0.45
Natural gas and oil depreciation, depletion and amortization	$ 1.35	$ 1.51	$ 2.34
Depreciation and amortization of other assets	$ 0.21	$ 0.27	$ 0.21
Interest expense[(c)]	$ 0.08	$ 0.22	$ 0.22
Interest Expense ($ in millions):			
Interest expense[(c)]	$ 99	$ 227	$ 192
Interest rate derivatives realized (gains) losses	(14)	(23)	(6)

Interest rate derivatives unrealized (gains) losses	(66)	(91)	85
Total interest expense	$ 19	$ 113	$ 271
Net Wells Drilled	1,149	1,003	1,733
Net Producing Wells as of the End of Period	22,617	22,919	22,813

(a) Includes NGLs.

(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.

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We manage our business as three separate operational segments: exploration and production; marketing, gathering and compression; and service operations, which is comprised of our wholly owned drilling and trucking operations. We refer you to Note 16 of the notes to our consolidated financial statements appearing in Item 8 of this report, which summarizes by segment our net income and capital expenditures for 2010, 2009 and 2008 and our assets as of December 31, 2010, 2009 and 2008.

Executive Summary

We are the second-largest producer of natural gas and a top 20 producer of oil and natural gas liquids in the U.S. We own interests in approximately 46,000 producing natural gas and oil wells that are currently producing approximately 3.0 bcfe per day, 87% of which is natural gas. Our strategy is focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S., primarily in the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas, and the Marcellus Shale in the northern Appalachian Basin of West Virginia and Pennsylvania. We also have substantial operations in the liquids-rich plays of the Eagle Ford Shale in South Texas, the Granite Wash, Cleveland, Tonkawa and Mississippian plays in the Anadarko Basin in western Oklahoma and the Texas Panhandle, the Niobrara Shale, Frontier and Codell plays in the Powder River and DJ Basins of Wyoming and Colorado and the Avalon, Bone Spring, Wolfcamp and Wolfberry plays in the Permian and Delaware Basins of West Texas and southern New Mexico, as well as various other plays, both conventional and unconventional, in the Mid-Continent, Williston Basin, Appalachian Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the U.S. We have also vertically integrated our operations and own substantial midstream, compression, drilling and oilfield service assets. As described below, we have agreed to sell our Fayetteville Shale assets in a transaction expected to close in the first half of 2011.

Chesapeake began 2010 with estimated proved reserves of 14.254 tcfe and ended the year with 17.096 tcfe, an increase of 2.842 tcfe, or 20%. During 2010, we replaced 1.035 tcfe of production with an estimated 3.877 tcfe of new proved reserves, for a reserve replacement rate of 375%. The 2010 proved reserve movement included 5.098 tcfe of extensions, 0.006 tcfe of downward performance revisions and 0.189 tcfe of positive revisions resulting from an increase in the twelve-month trailing average natural gas and oil prices between December 31, 2009 and December 31, 2010. During 2010, we acquired 0.089 tcfe of estimated proved reserves and divested 1.493 tcfe of estimated proved reserves.

Chesapeake continued the industry s most active drilling program in 2010 and drilled 1,445 gross (938 net) operated wells and participated in another 1,586 gross (211 net) wells operated by other companies. The company s drilling success rate was 98% for both company-operated and non-operated wells. Also during 2010, we invested $4.6 billion in operated wells (using an average of 131 operated rigs) and $815 million in non-operated wells (using an average of 123 non-operated rigs) for total drilling and completion costs of $5.4 billion, net of drilling and completion cost carries of $1.2 billion.

Our average daily production for 2010 of 2.836 bcfe consisted of 2.534 bcf (89% on a natural gas equivalent basis) and 50,397 bbls (11% on a natural gas equivalent basis) and was an increase of 355 mmcfe, or 14%, over the 2.481 bcfe of daily production for 2009. Total production for 2010 was 1,035 tcfe, an increase of 129.7 bcfe, or 14%, over 2009 total production of 905.5 bcfe. This was our 21st consecutive year of sequential production growth.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.3 million net acres) and 3-D seismic (27.9 million acres) in the U.S. This position includes the largest inventory of U.S. natural gas shale play leasehold (2.5 million net acres) as well as the largest combined leasehold position in two of the three largest new unconventional liquids-rich plays in the U.S. the Eagle Ford Shale and the Niobrara Shale. We are currently using 157 operated rigs to further develop our inventory of approximately 37,800 net drillsites.

Implementing Our Strategy

In recognition of the value gap between oil and natural gas prices, during the past two years Chesapeake has directed a significant portion of its technological, geo-scientific, leasehold acquisition and drilling expertise to identifying, securing and commercializing new unconventional liquids-rich plays. This planned transition will result in a more balanced portfolio between natural gas and liquids. To date, we have built leasehold positions and established production in multiple unconventional liquids-rich plays on approximately 4.1 million net leasehold acres. In 2010, we

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invested approximately $4.7 billion, net of divestitures, primarily in liquids-rich acreage, and we allocated approximately 30% of our $5.4 billion drilling and completion capital expenditures to these plays, compared to 10% in 2009. Our production of oil and natural gas liquids was 50,397 bbls per day during 2010, a 56% increase over the average for 2009 as a result of the increased development of our unconventional liquids-rich plays. We are projecting that the portion of drilling and completion capital expenditures allocated to liquids development will reach 50% in 2011 and 75% in 2012, and we expect to increase our oil and natural gas liquids production through our drilling activities to more than 150,000 bbls per day, or 20%-25% of total production, by year-end 2012.

This shift to a greater emphasis on liquids production is a continuation of our general business strategy outlined in Item 1. *Business*. Our goal is to create value for investors by focusing on developing unconventional resource plays onshore in the U.S. We do so by:

Growing through the drillbit We are the most active driller in the U.S., have our own fleet of 105 drilling rigs and are currently using 157 operated rigs. Our integrated marketing, gathering, compression and trucking services operations support our drilling activities so that we are able to manage the development of our leasehold efficiently and strategically.

Controlling substantial land and drilling location inventories and building regional scale We have been first movers in capturing both natural gas and liquids-rich unconventional leasehold and resources. During 2010, we invested heavily in a large number of highly competitive liquids-rich unconventional plays in order to accelerate our transition to increased liquids production. We now have achieved many of our leasehold acquisition goals and are becoming a significant seller of leasehold through new industry participation agreements and the pending sale of our Fayetteville Shale assets.

Developing proprietary technological advantages We support the scale of our operations with what we believe is the nation s largest inventory of 3-D seismic information and our state-of-the-art Reservoir Technology Center, or RTC. The RTC provides us a substantial competitive advantage, enabling us among other things to more quickly, accurately and confidentially analyze core data from wells drilled through unconventional formations on a proprietary basis and then identify new plays and leasing opportunities ahead of our competition and reduce the likelihood of investing in plays that ultimately are not commercial. Our 3-D seismic data permits us to image reservoirs of natural gas and oil that might otherwise remain undiscovered and to drill our horizontal wells more accurately inside the targeted formation.

Focusing on low costs We minimize lease operating costs and general and administrative expenses through focused activities, vertical integration and increasing scale. As of December 31, 2010, our operated wells accounted for approximately 80% of our daily production volume, providing us with a high degree of operational flexibility and cost control.

Mitigating natural gas and oil price risk We actively seek to manage our exposure to adverse market prices for natural gas and oil through our hedging program. Hedging allows us to predict with greater certainty the effective prices we will receive for our hedged natural gas and oil production. Our realized cash hedging gains for 2010 were $2.056 billion and since January 1, 2001 have been $6.478 billion.

Using industry participation agreements Through industry participation property sales, we have recouped substantially all of our lease acquisition costs in six of our significant unconventional operating areas, and we hold leasehold in new plays which we believe will be best developed through future industry participation agreements. In addition, drilling cost carries allow us to accelerate the development of new plays at a reduced cost to us. We pioneered the industry participation model of unconventional natural gas and oil development, and many other E&P companies have followed with their own industry participation agreements in the past two years.

Our strategic and financial plan for 2011-2012, announced on January 6, 2011 as our 25/25 Plan , calls for a 25% reduction in our outstanding long-term debt while growing net natural gas and oil production by 25% by the end of 2012. We expect to achieve the reduction in debt through asset monetizations. Among the several benefits of lower debt are lower borrowing costs, and we believe improved credit metrics will lead to a more favorable debt rating by the major ratings agencies.

Our goal of a 25% reduction in debt by year-end 2012 is part of our liability management plan begun in 2010. During 2010, we issued in private placements 2.6 million shares of two series of our 5.75% Cumulative Non-Voting Convertible Preferred Stock resulting in net proceeds to us of approximately $2.562 billion. We used the net proceeds of these preferred stock offerings to redeem in whole $1.934 billion in principal amount of four series of our outstanding senior notes. Additionally, through tender offers followed by redemptions, we purchased $1.5 billion aggregate principal amount of three additional series of senior notes. We funded the purchase of the notes tendered and redeemed with

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proceeds from a $2.0 billion public offering of two series of senior notes. We retired all series of our outstanding senior notes that were issued under our more restrictive indentures. Excess funds from our offerings were used to repay borrowings outstanding under our corporate revolving bank credit facility.

During 2011, we plan to take steps to extend the maturity profile of our outstanding indebtedness at advantageous rates. On February 11, 2011, the company issued $1.0 billion principal amount of 6.125% Senior Notes due 2021 in a registered public offering. We applied the net proceeds of $977 million from the offering to our revolving bank credit facility balance and plan to use proceeds from asset sales to retire at least $2.0 - $3.0 billion of our shorter-dated senior notes and also to reduce borrowings under our revolving bank credit facility.

Asset monetizations were also key elements of our strategic and financial plan in 2010 and early 2011, as described below.

Industry Participation Agreements

In 2010, Chesapeake completed its fourth and fifth significant industry participation agreements in unconventional natural gas and oil plays. In January 2010, Total E&P USA, Inc., a wholly owned subsidiary of Total S.A. (Total), purchased a 25% undivided interest in 270,000 net acres of our Barnett Shale leasehold, along with 840 bcfe of estimated proved reserves, for approximately $800 million in cash (plus $78 million of drilling and completion carries due from the effective date of the transaction to the closing date). Total agreed to fund 60% of our share of future drilling and completion expenditures in the Barnett Shale until it has paid a total of $1.45 billion in drilling and completion carries, which we expect to occur by year-end 2013. In November 2010, a wholly owned subsidiary of CNOOC Limited (CNOOC) purchased a 33.3% undivided interest in 600,000 net acres of our Eagle Ford Shale leasehold, along with 18.2 bcfe of estimated proved reserves, for approximately $1.12 billion in cash. In addition, CNOOC agreed to fund 75% of our share of drilling and completion costs in the Eagle Ford Shale until an additional $1.08 billion has been paid, which we expect to occur by year-end 2012. All proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized. Both Total and CNOOC have the right to participate proportionately with us in any additional leasehold we acquire in the Barnett Shale and the Eagle Ford Shale, respectively, at cost plus a fee.

The following table provides information about our remaining industry participation agreement drilling and completion carries as of December 31, 2010:

Shale Play	**Industry Participation Agreement Partner**	**Date**	**Carries Remaining ($ in millions)**
Marcellus	Statoil	November 2008	$ 1,362
Barnett	Total	January 2010	889
Eagle Ford	CNOOC	November 2010	1,030
			$ 3,281

On February 16, 2011, we entered into an industry participation agreement with a wholly owned U.S. subsidiary of CNOOC Limited (CNOOC) to develop our Niobrara Shale play in the DJ and Powder River Basins in northeast Colorado and southeast Wyoming. Under the terms of the industry participation agreement, CNOOC acquired a 33.3% undivided interest in approximately 800,000 net acres of our leasehold. We received $570 million in cash at closing, and CNOOC has agreed to fund 66.7% of our share of drilling and completion costs until an additional $697 million has been paid, which we expect to occur by year-end 2014. In addition, CNOOC has the right to a 33.3% participation in any additional leasehold we acquire in the area at cost plus a fee.

The drilling and completion carries in our industry participation agreements create a significant cost advantage that allows us to continue to lower finding costs. During 2010 and 2009, our drilling and completion costs included the benefit of approximately $1.151 billion and $1.154 billion, respectively, of drilling and completion carries. Our drilling and completion costs for 2011 through 2014 will continue to be partially offset by the use of our remaining drilling and completion carries associated with our industry participation agreements.

Volumetric Production Payments

We completed three volumetric production payments (VPPs) in 2010, bringing the total of such transactions to eight. The company s sixth VPP was completed in February 2010 for proceeds of approximately $180 million, or $3.95 per mcfe. In June 2010, we completed our seventh VPP for proceeds of approximately $335 million, or $8.73 per mcfe.

In September 2010, we completed our eighth VPP for proceeds of approximately $1.15 billion, or $2.93 per mcfe. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Other Asset Sales

In 2010, we sold non-core proved and unproved properties for proceeds of approximately $355 million. During 2010, as part of our industry participation agreements with Total, Statoil and PXP, we sold interests in additional leasehold in the Barnett, Marcellus and Haynesville Shale plays for proceeds of approximately $440 million that had an estimated original cost to us of $220 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

Chesapeake Midstream Partners, L.P. IPO and Asset Sale

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we and GIP formed to own, operate, develop and acquire midstream assets, completed an initial public offering of common units representing limited partner interests and received net proceeds of approximately $475 million. In connection with the closing of the offering and pursuant to the terms of our contribution agreement with GIP, CHKM distributed to GIP the approximate $62 million of net proceeds from the exercise of the offering over-allotment option, and Chesapeake and GIP contributed the interests of their midstream joint venture operating subsidiary to CHKM. Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests, and Chesapeake and GIP each have a 50% interest in the general partner of CHKM. CHKM makes quarterly distributions to its partners, and at the current annual rate of $1.35 per unit, Chesapeake receives quarterly distributions of approximately $20 million in respect of its limited partner and general partner interests. In 2010, we received cash distributions of $88 million from CHKM and its predecessor joint venture.

We account for our investment in CHKM under the equity method. During 2010, we recorded positive equity method adjustments of $89 million for our share of CHKM s income and recorded accretion adjustments of $14 million for our share of equity in excess of cost. As a result of CHKM s initial public offering, we recognized a $90 million gain on our investment, which represented our proportionate share of the excess of offering proceeds over the carrying value of our investment in CHKM and is reported in earnings (losses) from equity investees on our consolidated statements of operations.

On December 21, 2010, we sold our Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million and entered into ten-year gathering and compression agreements with CHKM. Additional information on the transaction is included in Item 1 under *Marketing, Gathering and Compression - Midstream Gathering Operations.*

Pending and Planned Asset Sales

Fayetteville Shale. On February 21, 2011, we entered into a purchase and sale agreement with a wholly owned subsidiary of BHP Billiton to sell all of our Fayetteville Shale assets, including approximately 487,000 net acres of leasehold and producing natural gas properties and midstream assets with approximately 420 miles of pipeline, for $4.75 billion in cash before certain deductions and standard closing adjustments. In the Fayetteville Shale, our current net production is approximately 415 mmcfe per day. Estimated proved reserves attributable to the Fayetteville Shale as of December 31, 2010 were 2.4 tcfe, or approximately 14% of our total proved reserves. As part of the transaction, we have agreed to provide essential services for up to one year for BHP Billiton s Fayetteville Shale properties for an agreed-upon fee. Closing of the transaction is subject to customary conditions, including filings under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and with the Committee on Foreign Investment in the United States. Closing is expected to occur in the first half of 2011.

Frac Tech Holdings, LLC and Chaparral Energy, Inc. Asset Sales. We plan to sell our 25.8% equity interest in Frac Tech Holdings, LLC and our 20% equity interest in Chaparral Energy, Inc. Each of the foregoing proposed transactions is subject to changes in market conditions and other factors, and there can be no assurance that we will complete any or all of these transactions on a timely basis or at all.

Other. During 2011, the company expects to enter into additional asset monetizations, including industry participation agreements in liquids-rich plays, new VPPs, certain midstream assets sales and various other smaller planned sales.

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Capital Expenditures

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Our current budgeted drilling and completion capital expenditures, net of drilling and completion carries, are $5.0 - $5.4 billion in 2011 and $5.4 - $5.8 billion in 2012. We anticipate funding all or substantially all budgeted drilling and completion capital expenditures using cash flow from operations in 2011 and 2012. We plan to fund our leasehold acquisition capital expenditures, together with other capital expenditure requirements, with a combination of revolving bank credit facility borrowings and proceeds from asset monetizations. As of December 31, 2010, we had made commitments to acquire additional proved and unproved properties in various transactions during the next twelve months for approximately $350 million.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity we use to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $5.117 billion in 2010, compared to $4.356 billion in 2009 and $5.357 billion in 2008. 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 impairments of assets, depreciation, depletion and amortization, deferred income taxes and changes in our derivative instruments. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. To mitigate the risk of declines in natural gas and oil prices and to provide more predictable future cash flow from operations, we have entered into various derivative instruments. Assuming future NYMEX natural gas settlement prices average $4.50 per mcf for 2011 and including the effect of the company s open derivatives as of February 22, 2011, closed contracts and previously collected call premiums, the company estimates its average natural gas price will be $5.98 per mcf for 2011. This estimate does not include the effect of basis differentials and gathering costs. Our natural gas and oil derivatives as of December 31, 2010 are detailed in Item 7A of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

Our $4.0 billion corporate revolving bank credit facility, our $300 million midstream revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use the credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $15.117 billion and repaid $13.303 billion in 2010, we borrowed $7.761 billion and repaid $9.758 billion in 2009, and we borrowed $13.291 billion and repaid $11.307 billion in 2008 from our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves are currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our midstream facility is secured by substantially all of our wholly owned midstream assets and is not subject to periodic borrowing base redeterminations. Our revolving bank credit facilities are described below under *Bank Credit Facilities*.

The following table reflects the proceeds from sales of securities we issued in 2010, 2009 and 2008 ($ in millions):

	2010		2009		2008	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$ 2,600	$ 2,562	$	$	$	$
Senior notes	2,000	1,967	1,425	1,346	800	787
Contingent convertible senior notes					1,380	1,349
Common stock					2,698	2,598
Total	$ 4,600	$ 4,529	$ 1,425	$ 1,346	$ 4,878	$ 4,734

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The following table reflects proceeds we received from our significant natural gas and oil asset monetizations in 2010, 2009 and 2008 ($ in millions):

	2010	2009	2008
Natural gas and oil property monetizations:			
CNOOC (Eagle Ford) industry participation agreement[(a)]	$ 1,170	$	$
TOT (Barnett) industry participation agreement[(b)]	1,361		
STO (Marcellus) industry participation agreement[(c)]	601	162	1,250
PXP (Haynesville) industry participation agreement[(d)]		1,490	1,722
BP (Fayetteville) industry participation agreement[(e)]		601	1,299
BP (Mid-Continent) divestiture			1,688
Volumetric production payments	1,622	408	1,579
Other divestitures	750	418	403
Total	$ 5,504	$ 3,079	$ 7,941

(a) 2010 included $50 million of drilling carries. As of December 31, 2010, $1.030 billion of drilling carry obligations remained outstanding.

(b) 2010 included $561 million of drilling carries. As of December 31, 2010, $889 million of drilling carry obligations remained outstanding.

(c) 2010 and 2009 proceeds were in the form of drilling carries. As of December 31, 2010, $1.362 billion of drilling carry obligations remained outstanding.

(d) 2009 and 2008 included $390 million and $72 million of drilling carries, respectively. 2009 also included a $1.1 billion acceleration of future drilling carries.

(e) 2009 and 2008 included $601 million and $199 million of drilling carries, respectively.

In December 2010, our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., sold its Springridge natural gas gathering system and related facilities in the Haynesville Shale to CHKM for $500 million.

In September 2009, we received $588 million from the sale of a noncontrolling interest in our midstream joint venture agreement with GIP.

In June 2009, we received net proceeds of $54 million from the mortgage financing of our regional Barnett Shale headquarters building in Fort Worth, Texas. The interest-only loan has a five-year term at a floating rate of prime plus 275 basis points. At our option, we may prepay the loan in full without penalty beginning in year four.

In April 2009, we financed 113 real estate surface assets in the Barnett Shale area in and around Fort Worth, Texas for net proceeds of approximately $145 million and entered into a master lease agreement under which we agreed to lease the assets for 40 years for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease.

In 2010, 2009 and 2008, we received $621 million and $109 million, and paid $167 million, respectively, for settlements of derivatives which were classified as cash flows from financing activities.

In 2010, we received cash distributions of $88 million from CHKM and its predecessor. In addition, we received cash distributions of $58 million from our equity investee, Frac Tech Holdings, LLC. These cash distributions were accounted for as a return on investment and reflected as cash flows from operating activities.

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 2010, 2009 and 2008. We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, changes in drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary.

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On June 21, 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with these redemptions, we recognized a loss of $69 million in 2010.

On July 22, 2010, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, $600 million in principal amount of our 6.375% Senior Notes due 2015. Associated with the redemption, we recognized a loss of $19 million in 2010.

On August 30, 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. On September 16, 2010, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the August 2010 tender offers and redemptions, we recognized a loss of $40 million in 2010.

We paid dividends on our common stock of $189 million, $181 million and $148 million in 2010, 2009 and 2008, respectively. The Board of Directors increased the quarterly dividend of common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. We paid dividends on our preferred stock of $92 million, $23 million and $35 million in 2010, 2009 and 2008, respectively. The increase in 2010 was due to the issuance of 2.6 million shares of preferred stock and the decrease from 2008 to 2009 was a result of conversions and exchanges of preferred stock into common stock during 2008 and 2009.

Credit Risk

Derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. On December 31, 2010, our commodity and interest rate derivative instruments were spread among 14 counterparties. Our multi-counterparty secured hedging facility includes 12 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($821 million at December 31, 2010) and exploration and production companies which own interests in properties we operate ($977 million at December 31, 2010). 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 2010 and 2008, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. During 2009, we recognized $13 million of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities was $8.503 billion in 2010, compared to $5.462 billion in 2009 and $9.965 billion in 2008. The majority of the increase in investing activities in 2010 was the result of our increased acquisition of unproved properties, primarily in liquids-rich areas, and exploration and development activities. Our investing activities in 2008 reflected our increasing focus on acquiring unproved properties in developing natural gas shale plays, converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential. Investing activities in 2009 were at a reduced rate in response to a low natural gas price environment, lower demand and the benefit of our drilling cost carries. Natural gas and oil investing activities increased in 2010 as we pursued our strategy to acquire and develop liquids-rich properties. In each of 2010, 2009 and 2008, we also invested in drilling rigs, gathering systems, compressors, and other property and equipment to support our natural gas and oil exploration, development and

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production activities. The following table details our cash used in (provided by) investing activities during 2010, 2009 and 2008 ($ in millions):

	2010	2009	2008
Natural Gas and Oil Investing Activities:			
Acquisitions of natural gas and oil proved properties	$ 243	$ 5	$ 372
Acquisition of natural gas and oil unproved properties	6,015	1,666	7,660
Exploration and development of natural gas and oil properties	5,061	3,410	5,789
Geological and geophysical costs[(a)]	181	162	315
Interest capitalized on unproved properties	687	598	561
Deposits for acquisitions of proved and unproved properties	43		12
Proceeds from divestitures of proved and unproved properties	(4,292)	(1,926)	(7,670)
Total natural gas and oil investing activities	7,938	3,915	7,039
Other Investing Activities:			
Additions to other property and equipment	1,326	1,683	3,073
Additions to investments	134	40	74
Proceeds from sales of other assets	(883)	(176)	(219)
Other	(12)		(2)
Total other investing activities	565	1,547	2,926
Total cash used in investing activities	$ 8,503	$ 5,462	$ 9,965

(a) Including related capitalized interest.

Bank Credit Facilities

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

	Corporate Credit Facility[(a)]	Midstream Credit Facility[(b)]
	($ in millions)	
Borrowing capacity	$ 4,000	$ 300
Maturity date	December 2015	July 2015
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2010	$ 3,612	$ 94
Letters of credit outstanding as of December 31, 2010	$ 13	$

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

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

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities contains provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

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

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in

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compliance with all covenants under the agreement at December 31, 2010. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $50 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

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

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

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

Hedging Facility

We have a multi-counterparty hedge facility with 12 counterparties that have committed to provide approximately 5.6 tcfe of hedging capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. In February 2011, we amended the agreement for the hedge facility primarily to allow us to protect our natural gas liquids production from price volatility and to allow for greater flexibility when hedging our anticipated production. As of December 31, 2010, we had hedged a total of 2.9 tcfe of our future production under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and natural gas liquids price and basis 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, and guarantees by our subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based hedging capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based hedging limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into hedges with the company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of December 31, 2010, senior notes represented approximately $8.9 billion of our total debt and consisted of the following ($ in millions):

7.625% senior notes due 2013	$	500
9.5% senior notes due 2015		1,425
6.25% euro-denominated senior notes due 2017[a]		796
6.5% senior notes due 2017		1,100
6.875% senior notes due 2018		600
7.25% senior notes due 2018		800
6.625% senior notes due 2020		1,400
6.875% senior notes due 2020		500
2.75% contingent convertible senior notes due 2035[b]		451
2.5% contingent convertible senior notes due 2037[b]		1,378
2.25% contingent convertible senior notes due 2038[b]		752
Discount on senior notes[c]		(777)
Interest rate derivatives[d]		9
	$	8,934

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3269 to 1.00 as of December 31, 2010. See Note 9 of our consolidated financial statements included in Item 8 of this report for information on our related foreign currency derivatives.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2010, 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 first quarter of 2011 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

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

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

(d) See Note 9 of our consolidated financial statements included in Item 8 of this report for discussion related to these instruments.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries, excluding CMD and its subsidiaries. See Note 17 of the consolidated financial statements included in Item 8 of this report for

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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.

Conversions and Exchanges of Contingent Convertible Senior Notes and Preferred Stock

In 2010, 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged their notes for shares of common stock in privately negotiated exchanges as summarized below:

Year	Contingent Convertible Senior Notes	Principal Amount ($ in millions)	Number of Common Shares (in thousands)
2010	2.25% due 2038	$ 11	299
2009	2.25% due 2038	$ 364	10,210
2008	2.75% due 2035	$ 239	8,841
	2.50% due 2037	272	8,417
	2.25% due 2038	254	6,655
		$ 765	23,913

In 2010, 2009 and 2008, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares (in thousands)	Number of Common Shares (in thousands)	Type of Transaction
2010	5.0% (series 2005)	5	21	Conversion
2009	6.25%	144	1,239	Conversion
	4.125%	3	183	Conversion
			1,422	
2008	5.0% (series 2005B)	3,654	10,443	Exchange
	4.5%	891	2,228	Exchange
	4.125%	(a)	2	Conversion
			12,673	

(a) Nominal amount.

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Contractual Obligations

The table below summarizes our cash contractual obligations as of December 31, 2010 ($ in millions):

		Payments Due By Period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt:					
Principal	$ 13,408	$	$ 500	$ 5,131	$ 7,777
Interest	5,193	595	1,173	996	2,429
Financing lease obligations and other	894	18	37	90	749
Operating lease obligations	916	170	345	287	114
Asset retirement obligations[a]	301		61	7	233
Purchase obligations[b]	5,054	930	874	797	2,453
Unrecognized tax benefits[c]	34	34			
Standby letters of credit	13	13			
Total contractual cash obligations	$ 25,813	$ 1,760	$ 2,990	$ 7,308	$ 13,755

(a) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2010 balance sheet.

(b) See Note 4 of the notes to our consolidated financial statements in Item 8 of this report for a description of transportation and drilling contract commitments.

(c) See Note 5 of the notes to our consolidated financial statements in Item 8 of this report for a description of unrecognized tax benefits.

Chesapeake has commitments to purchase any natural gas and oil associated with certain volumetric production payment transactions based on market prices at the time of production and the purchased gas will be resold.

Under minimum volume throughput agreements, Chesapeake has agreed to move fixed volumes of natural gas over certain time periods, usually multiple years, through certain midstream systems. At the end of the term or annually, Chesapeake will be invoiced for any shortfalls in such volume commitments.

Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company s hedging program at its quarterly Board meetings. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2010, our natural gas and oil derivative instruments were comprised of swaps, call options, put options, knockout swaps and basis protection swaps. Item 7A *Quantitative and Qualitative Disclosures About Market Ris*k contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Hedging allows us to predict with greater certainty the effective prices we will receive for our natural gas and oil production. We closely monitor the fair value of our derivative contracts and may elect to settle a contract prior to its scheduled maturity date in order to lock in a gain or loss. Commodity markets are volatile and Chesapeake s hedging activities are dynamic.

Mark-to-market positions under natural gas and oil derivative contracts fluctuate with commodity prices. As described above under *Hedging Facility*, our secured multi-counterparty hedging facility allows us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil derivatives by pledging natural gas and oil proved reserves.

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The estimated fair values of our natural gas and oil derivative contracts as of December 31, 2010 and 2009 are provided below.

	December 31, 2010	December 31, 2009
	($ in millions)	
Derivative assets (liabilities)[(a)]:		
Fixed-price natural gas swaps	$ 1,307	$ 662
Natural gas call options	(701)	(541)
Natural gas put options	(59)	(50)
Fixed-price natural gas knockout swaps		17
Fixed-price natural gas collars		92
Natural gas basis protection swaps	(55)	(50)
Fixed-price oil swaps	(31)	3
Oil call options[(b)]	(1,129)	(144)
Fixed-price oil knockout swaps	19	32
Estimated fair value	$ (649)	$ 21

(a) See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of this report for additional information concerning derivative transactions.

(b) During 2010 and 2009, we sold natural gas and oil call options on a portion of our projected production from 2011 to 2017 and received above-market fixed price natural gas swaps in 2010, 2011 and 2012.

Additional information concerning the changes in fair value of our natural gas and oil derivative contracts is as follows:

	2010	2009	2008
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 21	$ 1,305	$ (369)
Change in fair value of contracts	995	1,266	1,880
Fair value of new contracts when entered into	(581)	(21)	(569)
Contracts realized or otherwise settled	(1,691)	(2,102)	9
Fair value of contracts when closed	607	(427)	354
Fair value of contracts outstanding, as of December 31	$ (649)	$ 21	$ 1,305

Our realized and unrealized gains and losses on natural gas and oil derivatives during 2010, 2009 and 2008 were as follows:

	Years Ended December 31, 2010	2009	2008
		($ in millions)	
Natural gas and oil sales	$ 4,248	$ 3,291	$ 7,069
Realized gains (losses) on natural gas and oil derivatives[(a)]	2,056	2,346	(8)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives[(b)]	(634)	(624)	887
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(23)	36	(90)

Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858

(a) Consists of settled trades related to the production periods being reported.

(b) Consists of both temporary fluctuations in the mark-to-market values of non-qualifying trades and settled values of non-qualifying trades related to future production periods.

Changes in the fair value of natural gas and oil derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of settled derivative contracts are recorded in accumulated other comprehensive income and are transferred to earnings in the month of related production. These unrealized gains (losses), net of related tax effects, totaled ($156) million, $94 million and $386 million as of December 31, 2010, 2009 and 2008, respectively. Based upon the market prices at

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December 31, 2010, we expect to transfer to earnings approximately $15 million of net gain included in accumulated other comprehensive income during the next 12 months. A detailed explanation of accounting for natural gas and oil derivatives appears under *Application of Critical Accounting Policies Hedging* elsewhere in this Item 7.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives.

For interest rate derivative contracts designated as fair value hedges, changes in fair values of the derivatives are recorded on the consolidated balance sheets as assets or (liabilities), with corresponding offsetting adjustments to the debt s carrying value. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as interest expense and characterized as unrealized gains (losses).

Gains or losses from interest rate derivative contracts are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Interest expense on senior notes	$ 718	$ 765	$ 637
Interest expense on credit facilities	61	60	117
Capitalized interest	(716)	(633)	(585)
Realized (gains) losses on interest rate derivatives	(14)	(23)	(6)
Unrealized (gains) losses on interest rate derivatives	(66)	(91)	85
Amortization of loan discount and other	36	35	23
Total interest expense	$ 19	$ 113	$ 271

A detailed explanation of accounting for interest rate derivatives appears under *Application of Critical Accounting Policies Hedging* elsewhere in this Item 7.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. A detailed explanation of accounting for foreign currency derivatives appears under *Application of Critical Accounting Policies Hedging* elsewhere in this Item 7.

Results of Operations

General. For the year ended December 31, 2010, Chesapeake had net income of $1.774 billion, or $2.51 per diluted common share, on total revenues of $9.366 billion. This compares to a net loss of $5.830 billion, or $9.57 per diluted common share, on total revenues of $7.702 billion during the year ended December 31, 2009, and net income of $604 million, or $0.93 per diluted common share, on total revenues of $11.629 billion during the year ended December 31, 2008.

Natural Gas and Oil Sales. During 2010, natural gas and oil sales were $5.647 billion compared to $5.049 billion in 2009 and $7.858 billion in 2008. In 2010, Chesapeake produced and sold 1.035 tcfe of natural gas and oil at a weighted average price of $6.09 per mcfe, compared to 905.5 bcfe in 2009 at a weighted average price of $6.22 per mcfe, and 842.7 bcfe in 2008 at a weighted average price of $8.38 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of ($657) million, ($588) million and $797 million in 2010, 2009 and 2008, respectively). The decrease in prices in 2010 resulted in a decrease in revenue of $138 million and increased production resulted in a $807 million increase, for a total increase in revenues of $669 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from period to period was primarily generated from the drillbit.

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For 2010, we realized an average price per mcf of natural gas of $5.57, compared to $5.93 in 2009 and $8.09 in 2008 (weighted average prices for all years discussed exclude the effect of unrealized gains or losses on derivatives). Included in the 2010 realized price of natural gas are gains related to swaps that had an above-market fixed price on the origination date. We obtained these above-market swaps by selling out-year call options on a portion of our projected natural gas and oil production. See *Item 7A* for a complete listing of all of our derivative instruments. Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $62.71, $58.38 and $70.48 in 2010, 2009 and 2008, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $2.056 billion, or $1.99 per mcfe, in 2010, a net increase of $2.346 billion, or $2.59 per mcfe, in 2009 and a net decrease of $8 million, or $0.01 per mcfe, in 2008.

A change in natural gas and oil prices has a significant impact on our natural gas and oil revenues and cash flows. Assuming 2010 production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in 2010 revenues and cash flows of approximately $92 million and $89 million, respectively, and an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in 2010 revenues and cash flows of approximately $18 million and $17 million, respectively, without considering the effect of hedging activities.

The following tables show our production and prices by region for 2010, 2009 and 2008:

	2010						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Mid-Continent	233.2	4.09	13.8	56.60	315.9	31%	5.49
Haynesville/Bossier Shale	239.2	3.58			239.2	23	3.58
Barnett Shale	170.3	2.13	0.8	29.60	175.1	17	2.20
Fayetteville Shale	136.8	3.15			136.8	13	3.15
Permian and Delaware Basins	44.3	4.12	2.8	74.75	61.1	6	6.42
Marcellus Shale	51.2	3.91	0.3	42.09	53.0	5	4.01
Eagle Ford Shale	0.8	4.97	0.2	74.40	2.0		9.67
Rockies/Williston Basin	0.6	3.17	0.1	71.17	1.2		7.50
Other	48.5	3.68	0.4	69.69	50.9	5	4.08
Total[c]	924.9	3.43	18.4	58.67	1,035.2	100%	4.10

	2009						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Mid-Continent	258.7	3.78	7.7	55.25	304.8	34%	4.60
Haynesville/Bossier Shale	85.1	3.33	0.1	48.22	85.7	10	3.36
Barnett Shale	237.8	2.11	0.1	69.85	238.4	25	2.12
Fayetteville Shale	90.7	3.03			90.7	10	3.03
Permian and Delaware Basins	56.2	3.51	3.0	57.26	74.2	8	4.98
Marcellus Shale	21.9	4.30			21.9	2	4.30
Eagle Ford Shale							
Rockies/Williston Basin	0.6	1.46			0.6	1	1.46
Other	83.8	3.64	0.9	53.41	89.2	10	3.95
Total[c]	834.8	3.16	11.8	55.60	905.5	100%	3.63

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	2008						
	Natural Gas		Oil[a]		Total		
	(bcf)	($/mcf)[b]	(mmbbl)	($/bbl)[b]	(bcfe)	%	($/mcfe)[b]
Mid-Continent	315.5	7.92	6.9	94.12	357.0	42%	8.82
Haynesville/Bossier Shale	30.4	8.35	0.2	95.12	31.6	4	8.64
Barnett Shale	181.2	6.74			181.2	21	6.74
Fayetteville Shale	54.9	7.24			54.9	7	7.24
Permian and Delaware Basins	62.2	7.84	2.7	97.66	78.4	9	9.59
Marcellus Shale	1.0	9.42			1.0		9.42
Eagle Ford Shale							
Rockies/Williston Basin	1.0	5.40	0.1	90.22	1.6	1	7.81
Other	129.2	8.75	1.3	94.83	137.0	16	9.16
Total[c]	775.4	7.74	11.2	95.04	842.7	100%	8.39

(a) Includes NGLs

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

(c) 2010 production reflects the sale of a 25% industry participation interest in the company s Barnett Shale assets in January 2010 and various other asset sales, including VPP 6, VPP 7 and VPP 8.

Our average daily production of 2.836 bcfe for 2010 consisted of 2.534 bcf of natural gas and 50,397 bbls of oil. Our 2010 production of 1.035 tcfe was comprised of 924.9 bcf (89% on a natural gas equivalent basis) and 18.4 mmbbls (11% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 11% and our year-over-year growth rate of oil production was 56%. Our percentage of revenue from oil in 2010 was 18% of realized natural gas and oil revenue compared to 12% in 2009.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression sales and operating expenses consist of third-party revenue and operating expenses related to our midstream operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $3.479 billion in marketing, gathering and compression sales in 2010, with corresponding marketing, gathering and compression expenses of $3.352 billion, for a net margin before depreciation of $127 million. This compares to sales of $2.463 billion and $3.598 billion, expenses of $2.316 billion and $3.505 billion, and margins before depreciation of $147 million and $93 million in 2009 and 2008, respectively. In 2010, Chesapeake realized an increase in marketing, gathering and compression sales and operating expenses primarily due to an increase in third-party marketing, gathering and compression volumes. This increase was offset by a decrease in revenues, expenses and margin related to certain of our midstream assets that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010. In 2009, Chesapeake realized an increase in marketing, gathering and compression net margin primarily due to an increase in third-party marketing, gathering and compression volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $240 million in service operations revenue in 2010 with corresponding service operations expenses of $208 million, for a net margin before depreciation of $32 million. This compares to revenue of $190 million and $173 million, expenses of $182 million and $143 million and a net margin before depreciation of $8 million and $30 million in 2009 and 2008, respectively. Service operations margins have increased as service rates increased throughout 2010. The economic slowdown toward the end of 2008 and throughout 2009 caused decreased service rates and increased stacked rigs, resulting in much lower operating margins for 2009 when compared to 2010 and 2008.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $893 million in 2010, compared to $876 million and $889 million in 2009 and 2008, respectively. On a unit-of-production basis, production expenses were $0.86 per mcfe in 2010 compared to $0.97 and $1.05 per mcfe in 2009 and 2008, respectively. The per unit expense decreases in 2010 and 2009 were primarily the result of completing new high volume wells with lower per unit production costs.

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The following table shows our production expenses by region and our ad valorem tax expenses for 2010, 2009 and 2008 ($ in millions, except per unit):

	2010		2009		2008	
	Production Expenses	$/mcfe	Production Expenses	$/mcfe	Production Expenses	$/mcfe
Mid-Continent	$ 309	0.98	$ 300	$ 0.98	$ 362	1.01
Haynesville/Bossier Shale	65	0.27	33	0.39	37	1.33
Barnett Shale	142	0.81	158	0.66	128	0.71
Fayetteville Shale	40	0.29	23	0.25	13	0.24
Permian and Delaware Basins	94	1.54	112	1.52	134	1.67
Marcellus Shale	37	1.08	24	1.10	4	1.63
Eagle Ford Shale	3	1.50				
Rockies/Williston Basin	2	1.67	2			
Other	136	1.76	144	1.61	137	1.00
	828	0.80	796	0.88	815	0.96
Ad valorem tax	65	0.06	80	0.09	74	0.09
Total	$ 893	0.86	$ 876	0.97	$ 889	1.05

Production Taxes. Production taxes were $157 million in 2010 compared to $107 million in 2009 and $284 million in 2008. On a unit-of-production basis, production taxes were $0.15 per mcfe in 2010 compared to $0.12 per mcfe in 2009 and $0.34 per mcfe in 2008. The $50 million increase in production taxes from 2009 to 2010 is due to an increase in the realized average sales price of natural gas and oil of $0.47 per mcfe (excluding gains or losses on derivatives), and a production increase of 129.7 bcfe. The decrease in 2009 was due to a decrease in the realized average sales price of natural gas and oil of $4.76 per mcfe (excluding gains or losses on derivatives). In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher.

General and Administrative Expense. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties (see Note 10 of the notes to our consolidated financial statements included in Item 8 of this report), were $453 million in 2010, $349 million in 2009 and $377 million in 2008. General and administrative expenses were $0.44, $0.38 and $0.45 per mcfe for 2010, 2009 and 2008, respectively. The increase in 2010 is the result of the company s continued growth resulting in higher payroll and associated costs. The decrease in 2009 was primarily the result of decreased spending related to media relations. Included in general and administrative expenses is stock-based compensation of $84 million in 2010, $83 million in 2009 and $85 million in 2008. Restricted stock grants expense is based on the price of our common stock on the date of grant.

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Employee restricted stock awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 1 and Note 8 of the notes to our consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of our stock-based compensation.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. In addition, we capitalize internal costs that can be identified with construction of certain of our property, plant and equipment. We capitalized $384 million, $359 million and $352 million of internal costs in 2010, 2009 and 2008, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.394 billion, $1.371 billion and $1.970 billion during 2010, 2009 and 2008, respectively. 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 $1.35, $1.51 and $2.34 in 2010, 2009 and 2008, respectively. The decrease in the average rate from $2.34 in 2008 to $1.35 in 2010 is due primarily to reductions of our natural gas and oil full-cost pool resulting from our divestitures in 2008, 2009 and 2010, impairments of our full-cost pool in 2008 and 2009 as well as the addition of reserves through our drilling activities.

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Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $220 million in 2010, compared to $244 million in 2009 and $174 million in 2008. The average DD&A rate per mcfe was $0.21, $0.27 and $0.21 in 2010, 2009 and 2008, respectively. The decrease from 2009 to 2010 was primarily due to certain of our midstream assets that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010, offset by additional depreciation expense associated with the assets acquired over the past year. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 to 39 years, gathering facilities are depreciated over 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to twenty years. To the extent company-owned drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs.

Impairment of Natural Gas and Oil Properties. Due to lower commodity prices in the second half of 2008 and throughout 2009, we reported a non-cash impairment charge on our natural gas and oil properties of $11.0 billion in 2009 and $2.8 billion in 2008. 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 hedges.

(Gains) Losses on Sales of Other Property and Equipment. In 2010, we recorded a ($137) million gain associated with sales of other property and equipment which consisted of a ($157) million gain on the sale of our Springridge gas gathering system to our affiliate, CHKM, and a net $20 million loss related to various sales of other property and equipment, including the sale of pipe, gas gathering systems and other miscellaneous assets. In 2009, we recorded a $38 million loss on the sale of two gathering systems. There were nominal amounts of gains and losses on the sales of other property and equipment in 2008.

Other Impairments. In 2010, we recorded a $21 million impairment to natural gas gathering systems primarily related to the obsolescence of certain pipe inventory. In 2009, we recorded a $130 million impairment of other property and equipment and other assets. An $86 million impairment was associated with certain of our midstream assets contributed to our midstream joint venture in September 2009, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million midstream revolving bank credit facility that was reduced to $250 million as a result of the joint venture. Also in 2009, we recognized a $27 million charge associated with certain of our service operations assets and $13 million of bad debt expense related to potentially uncollectible receivables. In 2008, we recorded a $30 million impairment associated with certain of our midstream assets.

Restructuring Costs. In 2009, we recorded $34 million of restructuring and relocation costs in our Eastern Division and certain other workforce reduction costs. We reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring included termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 13 of our consolidated financial statements included in Item 8 of this report provides additional detail on the accounting for and reporting of these costs.

Interest Expense. Interest expense decreased to $19 million in 2010 compared to $113 million in 2009 and $271 million in 2008 as follows:

	Years Ended December 31, 2010	2009	2008
	($ in millions)		
Interest expense on senior notes	$ 718	$ 765	$ 637
Interest expense on credit facilities	61	60	117
Capitalized interest	(716)	(633)	(585)
Realized (gains) losses on interest rate derivatives	(14)	(23)	(6)
Unrealized (gains) losses on interest rate derivatives	(66)	(91)	85
Amortization of loan discount and other	36	35	23
Total interest expense	$ 19	$ 113	$ 271
Average long-term borrowings	$ 10,345	$ 11,167	$ 10,044

Interest expense, excluding unrealized (gains) losses on interest rate derivatives, was $0.08 per mcfe in 2010 compared to $0.22 per mcfe in both 2009 and 2008. The decrease in interest expense per mcfe from 2009 and 2008 is due to increased production volumes, a decrease in our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased in 2010 and 2009 as a result of a significant increase in unevaluated properties, the base on which interest is capitalized.

Earnings (Losses) from Equity Investees. Earnings (losses) from equity investees was $227 million, ($39) million and ($38) million in 2010, 2009 and 2008, respectively. The 2010 income consisted of $106 million related to our equity in the net income of certain investments and $121 million related to the initial public offering by CHKM and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value. The 2009 and 2008 losses related to our equity in the net losses of certain investments.

Loss on Redemptions or Exchanges of Debt. During 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in 2010. Also during 2010, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. We recognized a loss of $19 million in 2010 associated with the redemptions.

Additionally during 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with these tender offers and redemptions, we recognized a loss of $40 million in 2010.

Finally, in 2010, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 80% of the face value of the notes. Of the $11 million principal amount of convertible notes exchanged in 2010, $7 million was allocated to the debt component of the notes and the remaining $4 million was allocated to the equity conversion feature of the notes and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss (including a nominal amount of deferred charges associated with the exchanges).

In 2009, we privately exchanged approximately $364 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 10,210,169 shares of our common stock valued at approximately $262 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 75% of the face value of the notes. Of the $364 million principal amount of convertible notes exchanged in 2009, $227 million was allocated to the debt component and the remaining $137 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in a $40 million loss (including $5 million of deferred charges associated with the exchanges).

During 2008, we exchanged approximately $254 million, $272 million and $239 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038, 2.50% Contingent Convertible Senior Notes due 2037, and 2.75% Contingent Convertible Senior Notes due 2035, respectively, for an aggregate of 23,913,212 shares of our common stock valued at approximately $480 million. Through these transactions, we were able to redeem this debt for common stock valued at approximately 65% of the face value of the notes. Associated with these exchanges, we recorded a gain of $27 million. Of the combined $765 million principal amount of convertible notes exchanged in 2008, $515 million was allocated to the debt component and the remaining $250 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and the value of the common stock exchanged in these transactions resulted in a $35 million gain. This gain was partially offset by the write-off of $8 million in deferred charges associated with these exchanges.

Also during 2008, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction, we recorded a $31 million loss, which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Impairment of Investments. We recorded $16 million, $162 million and $180 million of impairments of certain investments in 2010, 2009 and 2008, respectively. Each of our investees has been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009 and 2010. The economic weakness has resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on certain investments.

Other Income. Other income was $16 million, $11 million and $27 million in 2010, 2009 and 2008, respectively. The 2010 income consisted of $8 million of interest income and $8 million of miscellaneous income. The 2009 income consisted of $8 million of interest income and $3 million of miscellaneous income. The 2008 income consisted of $22 million of interest income, $10 million of expense related to consent solicitation fees and $15 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $1.110 billion in 2010 compared to an income tax benefit of $3.483 billion in 2009 and income tax expense of $387 million in 2008. The entire income tax expense recorded in 2010 is deferred. Of the $4.593 billion increase in 2010, $4.564 billion was the result of the increase in net income before taxes and $29 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in 2010 compared to 37.5% in 2009 and 39% in 2008. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences. We expect our effective income tax rate to be 39% in 2011.

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $67 million in 2008. There were no losses on conversion/exchange of preferred stock in 2010 and 2009. In general, the loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. See Note 8 of the notes to our consolidated financial statements in Item 8 of this report for further detail regarding these transactions.

Application of Critical Accounting Policies

Readers of this report and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The three policies we consider to be the most significant are discussed below. The company s management has discussed each critical accounting policy with the Audit Committee of the company s Board of Directors.

The selection and application of accounting policies are an important process that changes as our business changes and as accounting rules are developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business.

Hedging. Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in natural gas and oil and changes in interest rates and foreign exchange rates. Recognized gains and losses on derivative contracts are reported as a component of the related transaction. Results of natural gas and oil derivative contracts are reflected in natural gas and oil sales, and results of interest rate and foreign exchange rate hedging contracts are reflected in interest expense. The changes in the fair value of derivative instruments not qualifying for designation as either cash flow or fair value hedges that occur prior to maturity are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales or interest expense. Cash flows from derivative contracts are classified in the same category within the statement of cash flows as the items being hedged, or on a basis consistent with the nature of the instruments.

Accounting guidance for derivatives and hedging establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as natural gas and oil cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings as natural gas and oil sales. Any change in the fair value resulting from ineffectiveness is

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recognized immediately in natural gas and oil sales. For derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings as interest expense. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings as interest expense. See *Hedging Activities* above and Item 7A. *Quantitative and Qualitative Disclosures About Market Ris*k for additional information regarding our hedging activities.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established 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. 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.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of natural gas and oil prices and, to a lesser extent, interest rates and foreign exchange rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2010, 2009 and 2008, the fair value of our derivatives was a liability of $761 million, a liability of $63 million and an asset of $1.165 billion, respectively.

Natural Gas and Oil Properties. The accounting for our business is subject to special accounting rules that are unique to the natural gas and oil industry. There are two allowable methods of accounting for natural gas and oil business activities: the successful efforts method and the full-cost method. Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of natural gas and oil properties are generally calculated on a well by well or lease or field basis versus the aggregated full-cost pool basis. Additionally, gain or loss is generally recognized on all sales of natural gas and oil properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher natural gas and oil depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in proved reserves and significantly alter the relationship between costs and proved reserves, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are grouped by major producing area where individual property costs are not significant and are assessed individually when individual costs are significant.

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We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. 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. For 2010 and 2009, 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 ended. Costs used are those as of the end of the appropriate quarterly period. For 2008, current prices and costs used are those as of the end of the appropriate 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 qualifying as cash flow hedges.

Two primary factors impacting this test are reserve levels and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which Chesapeake operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and our net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent Chesapeake establishes a valuation allowance or increases or decreases this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years;
- whether the carryforward period is so brief that it would limit realization of the tax benefit;
- future sales and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

If (i) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (ii) exploration, drilling and operating costs were to increase significantly beyond current levels, or (iii) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2010, we had deferred tax assets of $1.9 billion.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. Based on this guidance, we regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest related to these uncertain tax positions which is recognized in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses. Additional information about uncertain tax positions appears in

Note 5 of the notes to our consolidated financial statements.

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Disclosures About Effects of Transactions with Related Parties

Chief Executive Officer

As of December 31, 2010, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $30 million representing joint interest billings from December 2010 which were invoiced and timely paid in January 2011. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) and predecessor participation arrangements provided for in Mr. McClendon s employment agreements. Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the FWPP, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We are recognizing the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year beginning in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million was fully applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP. The incentive award is subject to a clawback equal to any unvested portion of the award if during the initial five-year term of the employment agreement, Mr. McClendon resigns from the company or is terminated for cause by the company.

Other Related Parties

During 2010, our 42%-owned affiliate, Chesapeake Midstream Partners, L.P. (CHKM), provided natural gas gathering and treating services to us in the ordinary course of business. In addition, there are various agreements in place whereby we support CHKM in various functions for which we are reimbursed. During 2010, our transactions with CHKM included the following:

	Year Ended December 31, 2010 ($ in millions)	
Amounts paid to CHKM:		
Gas gathering fees	$	378
Amounts received from CHKM:		
Compressor rentals		48
Inventory purchases		47
Other services provided[(a)]		73
Total amounts received from CHKM	$	168

(a) Includes amounts received related to the General and Administrative Services and Reimbursement Agreement, the Employee Secondment Agreement, the Shared Services Agreement and the Additional Services and Reimbursement Agreement agreed to at the formation of the joint venture.

As of December 31, 2010, we had a net payable to CHKM of $45 million.

During 2010 and 2009, our 26%-owned affiliate, Frac Tech Holdings, LLC, provided us hydraulic fracturing and other services in the ordinary course of business. During 2010 and 2009, we paid Frac Tech $89 million and $43 million, respectively, for these services. As of December 31, 2010 and 2009, we had $30 million and $8 million, respectively, due Frac Tech for services provided and not yet paid.

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Recently Issued 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 February 2010, the FASB amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance in 2010.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance in the Current Period. Adoption had no impact on our financial position or results of operations. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective beginning on January 1, 2011, and we do not expect the implementation to have a material impact on our financial position or results of operations. See Note 14 of the notes to our consolidated financial statements in Item 8 of this report for discussion regarding fair value measurements.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements other than historical fact and give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures, and anticipated asset acquisitions and sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under *Risk Factors* in Item 1A of this report and include:

- the volatility of natural gas and oil prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs;
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures;
- inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;

leasehold terms expiring before production can be established;

hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities;

drilling and operating risks, including potential environmental liabilities;

changes in legislation and regulation adversely affecting our industry and our business;

general economic conditions negatively impacting us and our business counterparties;

transportation capacity constraints and interruptions that could adversely affect our cash flow; and

losses possible from pending or future litigation.

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We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report and our other filings with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Natural Gas and Oil Hedging Activities

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

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

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

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

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

In 2009, we restructured many of our contracts that included knockout features as commodity prices decreased. The knockouts were typically restructured into straight swaps or collars based on strip prices at the time of the restructure. In the latter half of 2010, we restructured a portion of our call options by lowering the strike price on call options sold for 2012 through 2015 and used the value to buy back call options for the same periods. This increased our capacity to hedge additional volumes.

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As of December 31, 2010, our natural gas and oil derivative instruments consisted of the following:

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

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

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

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

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

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As of December 31, 2010, we had the following open natural gas and oil derivative instruments.

	Volume (bbtu)	Fixed	Weighted Average Price Put	Call (per mmbtu)	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Natural Gas:							
Swaps:							
Q1 2011	89,354	$ 5.60	$	$	$	Yes	$ 111
Q2 2011	91,023	5.35				Yes	83
Q3 2011	132,480	4.93				Yes	47
Q4 2011	132,480	4.93				Yes	8
2012	12,800	6.00				Yes	12
Other Swaps[(a)]:							
Q1 2011	142,545	6.43				No	298
Q2 2011	140,512	6.35				No	268
Q3 2011	85,880	6.70				No	183
Q4 2011	85,880	6.73				No	159
2012	122,180	6.19				No	138
Call Options:							
2012	161,077			6.54		No	(39)
2013	436,033			6.44		No	(171)
2014	330,183			6.44		No	(165)
2015	226,446			6.31		No	(140)
2016 2020	324,003			8.31		No	(186)
Put Options:							
Q1 2011	(9,000)		5.75			No	(13)
Q2 2011	(9,100)		5.75			No	(12)
Q3 2011	(16,560)		5.42			No	(18)
Q4 2011	(16,560)		5.48			No	(16)
Basis Protection Swaps (Non-Appalachian Basin):							
Q2 2011	19,147				(0.82)	No	(10)
Q3 2011	19,397				(0.82)	No	(10)
Q4 2011	6,545				(0.82)	No	(3)
2012	50,532				(0.78)	No	(22)
2013 2019	29,349				(0.69)	No	(9)
Basis Protection Swaps (Appalachian Basin):							
Q1 2011	11,674				0.14	No	(1)
Q2 2011	12,186				0.14	No	
Q3 2011	12,403				0.14	No	
Q4 2011	12,324				0.14	No	
2012 2022	134				0.11	No	
	Total Natural Gas						492

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	Volume (bbtu)	Fixed	Weighted Average Price Put (per mmbtu)	Call	Differential	Cash Flow Hedge	Fair Value ($ in millions)
Oil:							
Swaps:							
Q1 2011	180	$ 91.35	$	$	$	Yes	$
Q2 2011	182	91.35				Yes	
Q3 2011	184	91.35				Yes	(1)
Q4 2011	184	91.35				Yes	(1)
Other Swaps[(a)]:							
2012	1,830	100.00				No	(13)
2013	1,825	100.00				No	(16)
Call Options[(b)]:							
Q1 2011	2,250			72.81		No	(28)
Q2 2011	2,275			72.81		No	(33)
Q3 2011	2,300			72.81		No	(37)
Q4 2011	2,300			72.81		No	(40)
2012	15,644			79.82		No	(258)
2013	12,739			85.37		No	(226)
2014	8,707			87.72		No	(151)
2015	7,411			85.31		No	(140)
2016 2017	10,600			84.25		No	(216)
Knock-Out Swaps:							
Q1 2011	270	104.75	60.00			No	3
Q2 2011	273	104.75	60.00			No	3
Q3 2011	276	104.75	60.00			No	3
Q4 2011	276	104.75	60.00			No	2
2012	732	109.50	60.00			No	8
	Total Oil						(1,141)
Total Natural Gas and Oil							$ (649)

(a) Other swaps are swaps not qualifying for designation as cash flow hedges. Other oil swaps include options to extend existing swaps for an additional 12 months. The volume of such extendables in 2012 2013 is 3,655 mbbl at a weighted average price of $100.00/bbl.

(b) Included in oil call options are natural gas liquid call options in the amount of 5,000 bbls per day at $39.06/bbl for 2011 and $38.01/bbl for 2012.

In addition to the open derivative positions disclosed above, at December 31, 2010, we had $160 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas and oil sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below:

	December 31, 2010 ($ in millions)
Q1 2011	$ 68
Q2 2011	82
Q3 2011	79

Q4 2011		68
2012		42
2013		18
2014		(237)
2015		51
2016 2022		(11)
Total	$	160

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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 mitigated under our secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

The table below reconciles the years ended December 31, 2010, 2009 and 2008 changes in fair value of our natural gas and oil derivatives. Of the $649 million fair value liability as of December 31, 2010, $947 million relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $15 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($1,596) million relates to contracts maturing after 12 months. All transactions hedged as of December 31, 2010 are expected to mature by December 31, 2022.

	2010	2009	2008
		($ in millions)	
Fair value of contracts outstanding, as of January 1	$ 21	$ 1,305	$ (369)
Change in fair value of contracts	995	1,266	1,880
Fair value of new contracts when entered into	(581)	(21)	(569)
Contracts realized or otherwise settled	(1,691)	(2,102)	9
Fair value of contracts when closed	607	(427)	354
Fair value of contracts outstanding, as of December 31	$ (649)	$ 21	$ 1,305

The change in natural gas and oil prices during the year ended December 31, 2010 increased the value of our derivative assets by $995 million. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which were in a liability position of $581 million. We settled contracts for $1.691 billion, and we closed out contracts, which were in a liability position of $607 million. The realized gain or loss is recorded in natural gas and oil sales in the month of related production.

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

The components of natural gas and oil sales for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Natural gas and oil sales	$ 4,248	$ 3,291	$ 7,069
Realized gains (losses) on natural gas and oil derivatives	2,056	2,346	(8)
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(634)	(624)	887
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(23)	36	(90)
Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858

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Interest Rate Risk

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

	Years of Maturity						
	2011	2012	2013	2014	2015	Thereafter	Total
	($ in millions)						
Liabilities:							
Long-term debt fixed rate[(a)]	$	$	$ 500	$	$ 1,425	$ 7,777	$ 9,702
Average interest rate			7.63%		9.50%	5.29%	6.03%
Long-term debt variable rate	$	$	$	$	$ 3,706	$	$ 3,706
Average interest rate					2.13%		2.13%

(a) This amount does not include the discount included in long-term debt of ($777) million and interest rate derivatives of $9 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facilities. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed rate debt.

Interest Rate Derivatives

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

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

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

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

As of December 31, 2010, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Floating[(a)]	Fair Value Hedge	Net Premiums	Fair Value ($ in millions)
Fixed to Floating:						
Swaps						
Mature 2017 2020	$ 600	6.75%	3 mL plus 397 bp	Yes	$	$ (25)
Mature 2020	$ 250	6.88%	3 mL plus 351 bp	No		(4)
Call Options						
Expire Q2 2011	$ 250	6.88%	3 mL plus 351 bp	No	7	(2)

Swaption								
Expire Q1 2011	$	500	6.56%	3 mL plus 373 bp	No	3		(13)
Floating to Fixed:								
Swaps								
Mature 2014	$	1,050	2.19%	1 6 mL	No			(25)
						$ 10	$	(69)

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

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In addition to open derivative positions disclosed above, at December 31, 2010 we had $89 million of net hedging gains related to settled contracts that will be recorded within interest expense as realized gains (losses) as they are transferred from either our senior note liability or unrealized interest expense gains (losses) over the next ten-year term of the related senior notes.

Gains and losses from interest rate derivative transactions are reflected as adjustments to interest expense on the consolidated statements of operations. The components of interest expense for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Years Ended December 31,		
	2010	2009	2008
	($ in millions)		
Interest expense on senior notes	$ 718	$ 765	$ 637
Interest expense on credit facilities	61	60	117
Capitalized interest	(716)	(633)	(585)
Realized (gains) losses on interest rate derivatives	(14)	(23)	(6)
Unrealized (gains) losses on interest rate derivatives	(66)	(91)	85
Amortization of loan discount and other	36	35	23
Total interest expense	$ 19	$ 113	$ 271

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge. The fair value of the cross currency swap is recorded on the consolidated balance sheet as a liability of $43 million at December 31, 2010. The euro-denominated debt in notes payable has been adjusted to $796 million at December 31, 2010 using an exchange rate of $1.3269 to 1.00.

Additional Disclosures Regarding Derivative Instruments

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

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ITEM 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

It is the responsibility of the management of Chesapeake Energy Corporation to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management utilized the Committee of Sponsoring Organizations of the Treadway Commission s *Internal Control-Integrated Framework* (COSO framework) in conducting the required assessment of effectiveness of the company s internal control over financial reporting.

Management has performed an assessment of the effectiveness of the company s internal control over financial reporting and has determined the company s internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of the company s internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

/s/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman of the Board and Chief Executive Officer

/s/ DOMENIC J. DELL OSSO, JR.

Domenic J. Dell Osso, Jr.
Executive Vice President and Chief Financial Officer

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Chesapeake Energy Corporation,

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 12 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities as of January 1, 2010. Also as discussed in Note 10 to the consolidated financial statements, the Company changed the manner in which it estimates the quantities of oil and gas reserves in 2009 and the limitation on its capitalized costs as of December 31, 2009.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Tulsa, Oklahoma

March 1, 2011

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 102	$ 307
Accounts receivable	1,974	1,325
Short-term derivative instruments	947	692
Deferred income tax asset	139	24
Other current assets	104	98
Total Current Assets	3,266	2,446
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	38,952	35,007
Unevaluated properties	14,469	10,005
Natural gas gathering systems and treating plants	1,545	3,516
Other property and equipment	3,726	3,235
Total Property and Equipment, at Cost	58,692	51,763
Less: accumulated depreciation, depletion and amortization	(26,314)	(25,053)
Total Property and Equipment, Net	32,378	26,710
OTHER ASSETS:		
Investments	1,208	404
Long-term derivative instruments		60
Other long-term assets	327	294
Total Other Assets	1,535	758
TOTAL ASSETS	$ 37,179	$ 29,914
CURRENT LIABILITIES:		
Accounts payable	$ 2,069	$ 957
Short-term derivative instruments	15	27
Accrued interest	191	218
Other current liabilities	2,215	1,486
Total Current Liabilities	4,490	2,688
LONG-TERM LIABILITIES:		
Long-term debt, net	12,640	12,295
Deferred income tax liabilities	2,384	1,059
Long-term derivative instruments	1,693	787
Asset retirement obligations	301	282
Other long-term liabilities	407	462

Total Long-Term Liabilities	17,425	14,885
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders Equity:		
Preferred Stock, $0.01 par value, 20,000,000 shares authorized:		
7,254,515 and 4,659,515 shares issued and outstanding	3,065	466
Common stock, $0.01 par value, 1,000,000,000 shares authorized, 655,251,275 and 648,549,165 shares issued	7	6
Paid-in capital	12,194	12,146
Retained earnings (deficit)	190	(1,261)
Accumulated other comprehensive income (loss), net of tax of $102 million and ($62) million, respectively	(168)	102
Less: treasury stock, at cost; 1,221,299 and 877,205 common shares as of December 31, 2010 and 2009, respectively	(24)	(15)
Total Chesapeake Stockholders Equity	15,264	11,444
Noncontrolling interest		897
Total Equity	15,264	12,341
TOTAL LIABILITIES AND EQUITY	$ 37,179	$ 29,914

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2010	2009	2008
	($ in millions, except per share data)		
REVENUES:			
Natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858
Marketing, gathering and compression sales	3,479	2,463	3,598
Service operations revenue	240	190	173
Total Revenues	9,366	7,702	11,629
OPERATING COSTS:			
Production expenses	893	876	889
Production taxes	157	107	284
General and administrative expenses	453	349	377
Marketing, gathering and compression expenses	3,352	2,316	3,505
Service operations expense	208	182	143
Natural gas and oil depreciation, depletion and amortization	1,394	1,371	1,970
Depreciation and amortization of other assets	220	244	174
Impairment of natural gas and oil properties		11,000	2,800
(Gains) losses on sales of other property and equipment	(137)	38	
Other impairments	21	130	30
Restructuring costs		34	
Total Operating Costs	6,561	16,647	10,172
INCOME (LOSS) FROM OPERATIONS	2,805	(8,945)	1,457
OTHER INCOME (EXPENSE):			
Interest expense	(19)	(113)	(271)
Earnings (losses) from equity investees	227	(39)	(38)
Losses on redemptions or exchanges of debt	(129)	(40)	(4)
Impairment of investments	(16)	(162)	(180)
Other income	16	11	27
Total Other Income (Expense)	79	(343)	(466)
INCOME (LOSS) BEFORE INCOME TAXES	2,884	(9,288)	991
INCOME TAX EXPENSE (BENEFIT):			
Current income taxes		4	423
Deferred income taxes	1,110	(3,487)	(36)
Total Income Tax Expense (Benefit)	1,110	(3,483)	387
NET INCOME (LOSS)	1,774	(5,805)	604
Net (income) attributable to noncontrolling interest		(25)	
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	1,774	(5,830)	604
Preferred stock dividends	(111)	(23)	(33)

Loss on conversion/exchange of preferred stock			(67)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 1,663	$ (5,853)	$ 504
EARNINGS (LOSS) PER COMMON SHARE:			
Basic	$ 2.63	$ (9.57)	$ 0.94
Diluted	$ 2.51	$ (9.57)	$ 0.93
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.30	$ 0.30	$ 0.2925
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):			
Basic	631	612	536
Diluted	706	612	545

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2010	2009	2008
	($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME (LOSS)	$ 1,774	$ (5,805)	$ 604
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	1,614	1,615	2,144
Deferred income tax expense (benefit)	1,110	(3,487)	(36)
Unrealized (gains) losses on derivatives	592	497	(712)
Realized (gains) losses on financing derivatives	(621)	(154)	38
Stock-based compensation	147	140	132
Accretion of discount on contingent convertible notes	78	79	79
Restructuring costs		12	
(Gains) losses on sales of other property and equipment	(137)	38	
(Gains) losses on equity investments	(107)	39	38
Losses on redemptions or exchanges of debt	29	40	4
Impairment of natural gas and oil properties		11,000	2,800
Impairment of investments	16	162	180
Other impairments	21	130	30
Other	32	27	(2)
(Increase) decrease in accounts receivable and other assets	(769)	(31)	(22)
Increase (decrease) in accounts payable, accrued liabilities and other	1,338	54	80
Cash provided by operating activities	5,117	4,356	5,357
CASH FLOWS FROM INVESTING ACTIVITIES:			
Exploration and development of natural gas and oil properties	(5,242)	(3,572)	(6,104)
Acquisitions of natural gas and oil proved and unproved properties	(6,945)	(2,268)	(8,593)
Additions to other property and equipment	(1,326)	(1,683)	(3,073)
Proceeds from divestitures of proved and unproved properties	4,292	1,926	7,670
Proceeds from sales of other assets	883	176	219
Additions to investments	(134)	(40)	(74)
Other	(31)	(1)	(10)
Cash used in investing activities	(8,503)	(5,462)	(9,965)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from credit facilities borrowings	15,117	7,761	13,291
Payments on credit facilities borrowings	(13,303)	(9,758)	(11,307)
Proceeds from issuance of senior notes, net of offering costs	1,967	1,346	2,136
Proceeds from issuance of preferred stock, net of offering costs	2,562		
Proceeds from issuance of common stock, net of offering costs			2,598
Cash paid to redeem debt	(3,434)		(312)
Cash paid for common stock dividends	(189)	(181)	(148)
Cash paid for preferred stock dividends	(92)	(23)	(35)
Proceeds from sale of noncontrolling interest in midstream joint venture		588	
Realized gains on financing derivatives	621	109	(167)
Proceeds from mortgage of building		54	
Proceeds from sale/leaseback of real estate surface assets		145	

Net increase (decrease) in outstanding payments in excess of cash balance	20	(249)	330
Other	(88)	(128)	(30)
Cash provided by (used in) financing activities	3,181	(336)	6,356
Net increase (decrease) in cash and cash equivalents	(205)	(1,442)	1,748
Cash and cash equivalents, beginning of period	307	1,749	1
Cash and cash equivalents, end of period	$ 102	$ 307	$ 1,749

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Interest, net of capitalized interest	$ 11	$ 64	$ 97
Income taxes, net of refunds received	$ (291)	$ 7	$ 296

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of December 31, 2010, 2009 and 2008, dividends payable on our common and preferred stock were $90 million, $53 million and $50 million, respectively.

In 2010, 2009 and 2008, natural gas and oil properties were adjusted by $161 million, ($93) million and ($4) million, respectively, as a result of an increase (decrease) in accrued acquisition, exploration and development costs.

In 2010, 2009 and 2008, other property and equipment were adjusted by $14 million, ($53) million and $125 million, respectively, as a result in an increase (decrease) in accrued costs.

As of December 31, 2010 and 2009, we had recorded $371 million and $244 million, respectively, of various liabilities related to the purchase of proved and unproved properties.

In 2010, 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged their notes for shares of common stock in privately negotiated exchanges as summarized below:

Year	Contingent Convertible Senior Notes	Principal Amount ($ in millions)	Number of Common Shares Issued (in thousands)
2010	2.25% due 2038	$ 11	299
2009	2.25% due 2038	$ 364	10,210
2008	2.75% due 2035	$ 239	8,841
	2.50% due 2037	272	8,417
	2.25% due 2038	254	6,655
		$ 765	23,913

In 2009 and 2008, we issued 24,822,832 and 1,677,000 shares of common stock, valued at $429 million and $34 million, respectively, for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

In 2010, 2009 and 2008, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares	Type of Transaction
		(in thousands)		
2010	5.0% (series 2005)	5	21	Conversion
2009	6.25%	144	1,239	Conversion
	4.125%	3	183	Conversion
			1,422	
2008	5.0% (series 2005B)	3,654	10,443	Exchange
	4.5%	891	2,228	Exchange
	4.125%	(a)	2	Conversion
			12,673	

(a) Nominal amount.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

	Years Ended December 31, 2010	2009	2008
	($ in millions, except per share data)		
PREFERRED STOCK:			
Balance, beginning of period	$ 466	$ 505	$ 960
Issuance of 1,500,000, 0 and 0 shares of 5.75% preferred stock	1,500		
Issuance of 1,100,000, 0 and 0 shares of 5.75% preferred stock (series A)	1,100		
Conversion or exchange of 5,000, 146,801 and 4,545,414 shares of preferred stock for common stock	(1)	(39)	(455)
Balance, end of period	3,065	466	505
COMMON STOCK:			
Balance, beginning of period	6	6	5
Conversion or exchange of convertible notes and preferred stock for 319,274, 11,632,594 and 36,586,347 shares of common stock			
Issuance of 0, 0, and 51,750,000 shares of common stock			1
Issuance of 0, 24,822,832 and 1,677,000 shares of common stock for the purchase of proved and unproved properties			
Stock-based compensation	1		
Balance, end of period	7	6	6
PAID-IN CAPITAL:			
Balance, beginning of period	12,146	11,680	7,532
Issuance of 0, 0, and 51,750,000 shares of common stock			2,697
Issuance of 0, 24,822,832 and 1,677,000 shares of common stock for the purchase of proved and unproved properties		421	34
Issuance of 2.25% contingent convertible senior notes due 2038			345
Conversion or exchange of convertible notes and preferred stock for 319,274, 11,632,594 and 36,586,347 shares of common stock	9	301	934
Stock-based compensation	226	199	188
Offering/transaction expenses	(38)	(16)	(101)
Dividends on common stock	(95)	(185)	
Dividends on preferred stock	(44)	(22)	
Exercise of stock options	3	4	8
Allocation of joint venture capital to Global Infrastructure Partners		(294)	
Tax effect on equalization of partners capital		106	
Tax benefit (reduction in tax benefit) from exercise of stock-based compensation	(13)	(48)	43
Balance, end of period	12,194	12,146	11,680

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY (Continued)

	Years Ended December 31,		
	2010	**2009**	**2008**
	($ in millions, except per share data)		
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	$ (1,261)	$ 4,569	$ 4,144
Net income (loss) attributable to Chesapeake	1,774	(5,830)	604
Cumulative effect of accounting change, net of income taxes of $89 million	(142)		
Dividends on common stock	(95)		(158)
Dividends on preferred stock	(86)		(21)
Balance, end of period	190	(1,261)	4,569
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	102	267	(11)
Hedging activity	(265)	(231)	297
Investment activity	(5)	66	(19)
Balance, end of period	(168)	102	267
TREASURY STOCK COMMON:			
Balance, beginning of period	(15)	(10)	(6)
Purchase of 351,163, 227,827 and 159,430 shares for company benefit plans	(9)	(5)	(4)
Release of 7,069, 7,898 and 2,975 shares for company benefit plans			
Balance, end of period	(24)	(15)	(10)
TOTAL CHESAPEAKE STOCKHOLDERS EQUITY	15,264	11,444	17,017
NONCONTROLLING INTEREST:			
Balance, beginning of period	897		
Sale of noncontrolling interest in midstream joint venture		588	
Allocation of joint venture capital to Global Infrastructure Partners		294	
Distribution to partner		(10)	
Chesapeake Midstream Partners net income attributable to Global Infrastructure Partners		25	
Deconsolidation of investment in Chesapeake Midstream Partners	(897)		
Balance, end of period		897	
TOTAL EQUITY	$ 15,264	$ 12,341	$ 17,017

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2010	2009	2008
	($ in millions)		
Net income (loss)	$ 1,774	$ (5,805)	$ 604
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of $129 million, $413 million and $113 million, respectively	212	677	186
Reclassification of (gain) loss on settled contracts, net of income taxes of ($298) million, ($540) million and $35 million, respectively	(491)	(885)	55
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $9 million, ($14) million and $34 million, respectively	14	(23)	56
Unrealized (gain) loss on marketable securities, net of income taxes of ($3) million, $14 million and ($12) million, respectively	(5)	23	(19)
Reclassification of loss on investments, net of income taxes of $0, $26 million and $0, respectively		43	
Comprehensive income (loss)	1,504	(5,970)	882
(Income) attributable to noncontrolling interest		(25)	
Comprehensive income (loss) available to Chesapeake	$ 1,504	$ (5,995)	$ 882

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

Chesapeake Energy Corporation (Chesapeake or the company) is a natural gas and oil exploration and production company engaged in the exploration, development and acquisition of properties for the production of natural gas and oil from underground reservoirs, and we provide marketing and other midstream services. Our properties are located in Alabama, Arkansas, Colorado, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia and Wyoming.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

Change in Accounting Principles

Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we ceased consolidating our midstream joint venture with Global Infrastructure Partners within our financial statements and began to account for the joint venture under the equity method (see Note 12). Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our consolidated statement of equity for the year ended December 31, 2010. This charge reflects the difference between the carrying value of our initial investment in the joint venture, which was recorded at carryover basis as an entity under common control, and the fair value of our equity in the joint venture as of the formation date.

Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

Cash Equivalents

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.

Accounts Receivable

Our accounts receivable are primarily from purchasers of natural gas and oil and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of all our counterparties. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During 2010 and 2008, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. During 2009, we recognized $13 million of bad debt expense related to potentially uncollectible receivables.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounts receivable consists of the following components:

	December 31,			
	2010		2009	
	($ in millions)			
Natural gas and oil sales	$	821	$	743
Joint interest		977		394
Service operations		10		7
Related parties[(a)]		30		15
Other		154		190
Allowance for doubtful accounts		(18)		(24)
Total accounts receivable	$	1,974	$	1,325

(a) See Note 6 for discussion of related party transactions.

Natural Gas and Oil Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 10). Capitalized costs are amortized on a composite unit-of-production method based on proved natural gas and oil reserves. Estimates of our proved reserves as of December 31, 2010 were prepared by both third-party engineering firms and Chesapeake s internal staff. Approximately 78% of these proved reserves estimates (by volume) at December 31, 2010 were prepared by independent engineering firms. In addition, our internal engineers review and update our reserves on a quarterly basis. The average composite rates used for depreciation, depletion and amortization of natural gas and oil properties were $1.35 per mcfe in 2010, $1.51 per mcfe in 2009 and $2.34 per mcfe in 2008.

Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in proved reserves and significantly alter the relationship between costs and the value of proved reserves, in which case a gain or loss is recognized.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. Unevaluated properties are grouped by major prospect area where individual property costs are not significant and are assessed individually when individual costs are significant.

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the Securities and Exchange Commission on a quarterly basis. 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 calculating estimated future net revenues, current prices are calculated as the unweighted arithmetical average of natural gas and oil prices on the first day of each month within the 12-month period ended. Costs used are those as of the end of the appropriate 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 qualifying as cash flow hedges. Based on average prices on the first day of each month within the 12-month period ending December 31, 2010, these cash flow hedges increased the full-cost ceiling by $176 million. Our qualifying cash flow hedges as of December 31, 2010, which consisted of swaps, covered 450 bcfe and 13 bcfe in 2011 and 2012, respectively. Our natural gas and oil hedging activities are discussed in Note 9 of these consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Two primary factors impacting the ceiling test are reserve levels and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is written off as an expense.

We account for seismic costs in accordance with Rule 4-10 of Regulation S-X. Specifically, Rule 4-10 requires that all companies that use the full-cost method capitalize exploration costs as part of their natural gas and oil properties (i.e., full-cost pool). Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Further, exploration costs include, among other things, geological and geophysical studies and salaries and other expenses of geologists, geophysical crews and others conducting those studies. Such costs are capitalized as incurred. Seismic costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties. The company reviews its unproved properties and associated seismic costs quarterly in order to ascertain whether impairment has occurred. To the extent that seismic costs cannot be directly associated with specific unevaluated properties, they are included in the amortization base as incurred.

Other Property and Equipment

Other property and equipment consists primarily of natural gas gathering systems and treating plants, drilling rigs and associated equipment, land, buildings and improvements, natural gas compressors, vehicles and office equipment. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operating costs. Other property and equipment costs, excluding land, are depreciated on a straight-line basis. A summary of other property and equipment and the useful lives is as follows:

	December 31, 2010	December 31, 2009	Useful Life (in years)
	($ in millions)		
Natural gas gathering systems and treating plants	$ 1,545	$ 3,516	20
Buildings and improvements	902	805	10 39
Drilling rigs and equipment	900	687	3 15
Natural gas compressors	304	325	20
Land	911	868	
Other	709	550	2 7
Total other property and equipment, at cost	5,271	6,751	
Less: accumulated depreciation and amortization	(720)	(834)	
Total other property and equipment, net	$ 4,551	$ 5,917	

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. For 2010, we recorded an impairment of $21 million to natural gas gathering systems primarily related to the obsolescence of certain midstream assets. For 2009, we recorded an impairment of $86 million associated with certain of our midstream assets and $27 million associated with certain of our service operations assets. For 2008, we recorded an impairment of $30 million associated with certain of our midstream assets.

Investments

Investments in securities are accounted for under the equity method in circumstances where we are deemed to exercise significant influence over the operating and investing policies of the investee but do not have control. Under the equity method, we recognize our share of the investee s earnings in our consolidated statements of operations. Investments in securities not accounted for under the equity method are accounted for under the cost method.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investments in marketable equity securities accounted for under the cost method have been designated as available for sale and, as such, are recorded at fair value. We evaluate our investments for impairment in value and recognize a charge to earnings when any identified impairment is judged to be other than temporary. For 2010, 2009 and 2008, we recorded investment impairments of $16 million, $162 million and $180 million, respectively. See Note 12 for further discussion of investments.

Capitalized Interest

During 2010, 2009 and 2008, interest of approximately $711 million, $627 million and $585 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. An additional $5 million and $6 million was capitalized in 2010 and 2009, respectively, on midstream assets which were under construction. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings.

Accounts Payable and Other Current Liabilities

Included in accounts payable at December 31, 2010 and 2009, are liabilities of approximately $251 million and $231 million, respectively, representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Other current liabilities as of December 31, 2010 and 2009 are detailed below:

	December 31, 2010	December 31, 2009
	($ in millions)	
Revenues and royalties due others	$ 732	$ 565
Accrued drilling and production costs	398	230
Accrued acquisition costs	371	244
JIB prepayments received	221	102
Accrued payroll	123	96
Accrued dividends	90	53
Other	280	196
Total Other Current Liabilities	$ 2,215	$ 1,486

Debt Issuance and Hedge Facility Costs

Included in other long-term assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facilities and hedging facilities. The remaining unamortized issuance costs at December 31, 2010 and 2009 totaled $162 million and are being amortized over the life of the senior notes, revolving credit facilities or hedging facilities.

Asset Retirement Obligations

We recognize liabilities for retirement obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is removed. See Note 15 for further discussion of asset retirement obligations.

Revenue Recognition

Natural Gas and Oil Sales. Revenue from the sale of natural gas and oil is recognized when title passes, net of royalties due to third parties.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas Imbalances. We follow the sales method of accounting for our natural gas revenue whereby we recognize sales revenue on all natural gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining natural gas reserves on the underlying properties. The natural gas imbalance net position at December 31, 2010 and 2009 was a liability of $7 million.

Marketing Gathering and Compression Sales. Chesapeake takes title to the natural gas it purchases from other working interest owners in operated wells, arranges for transportation and delivers the natural gas to third parties, at which time revenues are recorded. Chesapeake s results of operations related to its natural gas and oil marketing activities are presented on a gross basis, because we act as a principal rather than an agent. Gathering and compression revenues consist of fees recognized for the gathering, treating and compression of natural gas. Revenues are recognized when the service is performed and are based upon non-regulated rates and the related gathering, treating and compression volumes. All significant intercompany accounts and transactions have been eliminated.

Service Operations Revenue. We have drilling rig and trucking operations which primarily service Chesapeake-operated drilling operations. Revenues are recognized when the service is performed. All significant intercompany accounts and transactions have been eliminated.

Hedging

Chesapeake uses commodity price and financial risk management instruments to mitigate our exposure to price fluctuations in natural gas and oil and changes in interest rates and foreign exchange rates. Results of natural gas and oil derivative transactions are reflected in natural gas and oil sales and results of interest rate and foreign exchange rate hedging transactions are reflected in interest expense.

We have established the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. 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.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness is recognized immediately in natural gas and oil sales. For interest rate derivative instruments designated as fair value hedges, changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statement of cash flows.

Stock-Based Compensation

Chesapeake s stock-based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the fair value at the date of grant of those awards. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, production expenses, marketing, gathering and compression expenses or service operations expense.

For the years ended December 31, 2010, 2009 and 2008, we recorded the following stock-based compensation:

	2010	2009	2008
		($ in millions)	
Natural gas and oil properties	$ 120	$ 112	$ 109
General and administrative expenses	84	74	85
Production expenses	35	34	30
Marketing, gathering and compression expenses	18	16	11
Service operations expense	9	8	6
Restructuring costs		9	
Total	$ 266	$ 253	$ 241

Cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (excess tax benefits) are classified as financing cash inflows in our consolidated statements of cash flows. For the years ended December 31, 2010 and 2009, we recognized a reduction in tax benefits related to stock-based compensation of $13 million and $48 million which is reported in operating activities on our consolidated statements of cash flows. For the year ended December 31, 2008, we recognized $43 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our consolidated statements of cash flows.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2009 and 2008 to conform to the presentation used for the 2010 consolidated financial statements.

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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2010, all outstanding securities that are convertible into common stock were included in the calculation of diluted EPS. For the years ended December 31, 2009 and 2008, the following securities and associated adjustments to net income, comprised of dividends and loss on conversions/exchanges, were not included in the calculation of diluted EPS, as the effects were antidilutive:

	Net Income Adjustments (in millions)	Shares ($ in millions)
Year Ended December 31, 2009:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	$ 12	6
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
Common stock equivalent of our preferred stock outstanding prior to conversion:		
6.25% mandatory convertible preferred stock	$ 1	1
Unvested restricted stock	$	6
Outstanding stock options	$	1
Year Ended December 31, 2008:		
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	$ 12	6
5.00% cumulative convertible preferred stock (series 2005B)	$ 10	5
6.25% mandatory convertible preferred stock	$ 2	1
Common stock equivalent of our preferred stock outstanding prior to conversion:		
4.50% cumulative convertible preferred stock	$ 14	1
5.00% cumulative convertible preferred stock (series 2005B)	$ 62	4

As a result of the net loss to common stockholders for the year ended December 31, 2009, both basic weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares outstanding, which are used in computing diluted EPS, were 612 million shares. The basic and diluted loss per common share was $9.57.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A reconciliation for the years ended December 31, 2010 and 2008 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
		(in millions, except per share data)	
For the Year Ended December 31, 2010:			
Basic EPS	$ 1,663	631	$ 2.63
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	49	32	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	39	25	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	11	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	12	6	
Unvested restricted stock		6	
Outstanding stock options		1	
Diluted EPS	$ 1,774	706	$ 2.51
For the Year Ended December 31, 2008:			
Basic EPS	$ 504	536	$ 0.94
Effect of Dilutive Securities:			
Effect of contingent convertible senior notes outstanding during the period		1	
Unvested restricted stock		6	
Outstanding stock options		2	
Diluted EPS	$ 504	545	$ 0.93

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Debt

Our long-term debt consisted of the following at December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	($ in millions)	
7.5% senior notes due 2013	$	$ 364
7.625% senior notes due 2013	500	500
7.0% senior notes due 2014		300
7.5% senior notes due 2014		300
6.375% senior notes due 2015		600
9.5% senior notes due 2015	1,425	1,425
6.625% senior notes due 2016		600
6.875% senior notes due 2016		670
6.25% euro-denominated senior notes due 2017[(a)]	796	860
6.5% senior notes due 2017	1,100	1,100
6.25% senior notes due 2018		600
6.875% senior notes due 2018	600	
7.25% senior notes due 2018	800	800
6.625% senior notes due 2020	1,400	
6.875% senior notes due 2020	500	500
2.75% contingent convertible senior notes due 2035[(b)]	451	451
2.5% contingent convertible senior notes due 2037[(b)]	1,378	1,378
2.25% contingent convertible senior notes due 2038[(b)]	752	763
Corporate revolving bank credit facility	3,612	1,892
Midstream revolving bank credit facility	94	
Midstream joint venture revolving bank credit facility[(c)]		44
Discount on senior notes[(d)]	(777)	(921)
Interest rate derivatives[(e)]	9	69
Total notes payable and long-term debt	$ 12,640	$ 12,295

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3269 to 1.00 and $1.4332 to 1.00 as of December 31, 2010 and 2009, respectively. See Note 9 for information on our related foreign currency derivatives.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder s option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is when the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the fourth quarter of 2010, 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 first quarter of 2011 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

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

(c) Effective January 1, 2010, our midstream joint venture, CMP, was no longer consolidated in accordance with new authoritative guidance. See Note 1 for further details.

(d) Discount at December 31, 2010 and 2009 included $711 million and $794 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(e) See Note 9 for further discussion related to these instruments.

Senior Notes

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries, excluding CMD and its subsidiaries. See Note 17 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.

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

On June 21, 2010, we redeemed for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in 2010.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On July 22, 2010, we redeemed for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. Associated with the redemption, we recognized a loss of $19 million in 2010.

On August 3, 2010, we filed a shelf registration statement on Form S-3 with the SEC for the offering from time to time of debt securities.

On August 17, 2010, we completed a public offering of $2.0 billion aggregate principal amount of senior notes for net proceeds of approximately $1.967 billion. The offering consisted of $600 million of 6.875% Senior Notes due 2018 and $1.4 billion of 6.625% Senior Notes due 2020. Both series were priced at par.

On August 30, 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. On September 16, 2010, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the August 2010 tender offers and redemptions, we recognized a loss of $40 million in 2010.

During 2010, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $11 million in aggregate principal amount for an aggregate of 298,500 shares of our common stock in privately negotiated exchanges. Associated with these exchanges, we recognized a loss of $2 million in 2010.

During 2009, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $364 million in aggregate principal amount for an aggregate of 10,210,169 shares of our common stock in privately negotiated exchanges. Associated with these exchanges, we recognized a loss of $40 million in 2009.

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

Bank Credit Facilities

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

	Corporate Credit Facility(a)	Midstream Credit Facility(b)
	($ in millions)	
Borrowing capacity	$ 4,000	$ 300
Maturity date	December 2015	July 2015
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of December 31, 2010	$ 3,612	$ 94
Letters of credit outstanding as of December 31, 2010	$ 13	$

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

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

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities contains provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility

Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at December 31, 2010. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $50 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million.

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

Midstream Credit Facility

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

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

Other Financings

In 2009, we financed 113 real estate surface assets in the Barnett Shale area for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in 2010. As of December 31, 2010, 111 assets were leased and the minimum aggregate undiscounted future lease payments were approximately $828 million. This obligation is recorded in other long-term liabilities on our consolidated balance sheets.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

4. Contingencies and Commitments

Litigation

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

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas 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 believes that it has substantial defenses to the claims made in these purchase and sale cases.

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

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability and is not aware of any potential material environmental issues or claims at December 31, 2010. There are currently enforcement actions pending against us related to alleged methane migration in Pennsylvania and compliance with Clean Water Act permitting requirements in West Virginia. While these actions may result in monetary sanctions, we do not expect that they will have a material adverse effect on our operations.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Rig Leases

In a series of transactions since 2006, our drilling subsidiaries have sold 86 drilling rigs and related equipment for $717 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to service operations expense over the lease term. Under the rig leases, we can exercise an early purchase option after five and one-half to seven years or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, in most cases we have the option to renew the rig lease for a negotiated renewal term at a periodic lease payment equal to the fair market rental value of the rigs as determined at the time of renewal.

Compressor Leases

Through various transactions since 2007, our compression subsidiary has sold 2,234 compressors, a significant portion of its existing compressor fleet, for $517 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years. The lease obligations are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss is amortized to marketing, gathering and compression expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew the lease for negotiated new terms at the expiration of the lease. As of December 31, 2010, approximately 80 new compressors were on order for delivery in 2011 at a cost of approximately $20 million. Our intent is to sell and lease back those compressors as they are delivered if acceptable leasing arrangements are available to us.

Future operating lease obligations related to rigs, compressors and other equipment or property are not recorded in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future lease payments are presented below:

	December 31, 2010			
	Rigs	Compressors	Other	Total
	($ in millions)			
2011	$ 101	$ 61	$ 8	$ 170
2012	102	63	5	170
2013	102	68	4	174
2014	87	122	2	211
2015	29	47	1	77
After 2015	45	68	1	114
Total	$ 466	$ 429	$ 21	$ 916

Rent expense, including short-term rentals, for the years ended December 31, 2010, 2009 and 2008 was $161 million, $149 million and $133 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from 2011 to 2099. These commitments are not recorded in the accompanying consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. The aggregate undiscounted amounts of such required demand payments are presented below:

	December 31, 2010 ($ in millions)
2011	$ 353
2012	414
2013	407
2014	402
2015	395
After 2015	2,453
Total	$ 4,424

Drilling Contracts

Currently, we have contracts with various drilling contractors to lease approximately 61 rigs with terms of four months to three years. These commitments are not recorded in the accompanying consolidated balance sheets. The aggregate undiscounted minimum future commitments are presented below:

	December 31, 2010 ($ in millions)
2011	$ 196
2012	35
2013	18
Total	$ 249

Natural Gas and Oil Purchase Obligations

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Minimum Volume Commitments

We are a party to two gas gathering agreements with a subsidiary of Chesapeake Midstream Partners, L.P. (see Note 12), pursuant to which we have committed to deliver annually specified minimum volumes of natural gas. At the end of the term or annually, Chesapeake will be invoiced for any shortfalls in such volume deliveries at the rate specified in the agreement. Volume commitments remaining under the agreement relating to our Barnett Shale production as of December 31, 2010 were as follows:

	Bcf
2011	313
2012	325
2013	338
2014	351
2015	365
After 2015[(a)]	1,321
Total	3,013

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

Volume commitments remaining under the agreement relating to our Haynesville Shale production as of December 31, 2010 were as follows:

	Bcf
2011	104
2012	118
2013	135
Total	357

In addition, Chesapeake has entered into commitments to deliver approximately 2.56 tcf through December 2023 to third-party midstream companies.

Net Acreage Maintenance Commitments

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

Other Commitments

As of December 31, 2010, we had commitments to acquire additional proved and unproved properties in various transactions during the next twelve months for approximately $350 million.

5. Income Taxes

The components of the income tax provision (benefit) for each of the periods presented below are as follows:

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Current	$	$ 4	$ 423
Deferred	1,110	(3,487)	(36)
Total	$ 1,110	$ (3,483)	$ 387

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The effective income tax expense (benefit) differed from the computed expected federal income tax expense on earnings before income taxes for the following reasons:

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Income tax expense (benefit) at the federal statutory rate (35%)	$ 1,009	$ (3,251)	$ 347
State income taxes (net of federal income tax benefit)	78	(275)	24
Other	23	43	16
Total	$ 1,110	$ (3,483)	$ 387

Deferred income taxes are provided to reflect temporary differences in the basis of net assets for income tax and financial reporting purposes. The tax-effected temporary differences and tax loss carryforwards which comprise deferred taxes are as follows:

	Years Ended December 31	
	2010	2009
	($ in millions)	
Deferred tax liabilities:		
Natural gas and oil properties	$ (2,074)	$ (96)
Other property and equipment	(184)	(184)
Derivative instruments		(265)
Volumetric production payments	(1,394)	(937)
Contingent convertible debt	(493)	(464)
Other		(8)
Deferred tax liabilities	(4,145)	(1,954)
Deferred tax assets:		
Net operating loss carryforwards	1,386	592
Derivative instruments	115	
Asset retirement obligation	114	107
Investments	40	32
Deferred stock compensation	84	57
Accrued liabilities	25	22
Alternative minimum tax credits	11	25
Oklahoma statutory depletion	93	84
Other	32	
Deferred tax assets	1,900	919
Total deferred tax asset (liability)	$ (2,245)[a]	$ (1,035)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 139	$ 24

Non-current deferred income tax liability	(2,384)	(1,059)
Total	$ (2,245)	$ (1,035)

(a) In addition to the income tax expense of $1.110 billion, activity during 2010 includes an increase to deferred tax liabilities of $13 million related to stock-based compensation and a decrease to deferred tax liabilities for deferred tax assets of $161 million related to derivative instruments, $3 million related to investments and $89 million related to the cumulative effect of an accounting change. These items were not recorded as part of the provision for income taxes. In addition, the activity includes an increase to deferred tax liabilities of $240 million related to federal and state income tax refunds, $13 million related to alternative minimum tax credits used and $87 million related to uncertain tax positions.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2010, we classified $139 million of deferred tax assets as current that were attributable to net operating losses expected to be utilized in 2011, which was offset by current temporary differences associated with derivative assets and other items. As of December 31, 2009, we classified $24 million of deferred tax assets as current that were attributable to net operating losses expected to be utilized during 2010, which were offset by current temporary differences associated with derivative assets and other items.

At December 31, 2010, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $3.674 billion. Additionally, we had $2.642 billion of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income. The NOL carryforwards expire from 2019 through 2030. The value of these carryforwards depends on the ability of Chesapeake to generate taxable income.

The ability of Chesapeake to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of Chesapeake is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by us during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of Chesapeake.

In the event of an ownership change (as defined for income tax purposes), Section 382 of the Code imposes an annual limitation on the amount of a corporation s taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains (as defined in the Code) inherent in the assets sold. Certain NOLs acquired through various acquisitions are also subject to limitations.

The following table summarizes our net operating losses as of December 31, 2010 and any related limitations:

	Total	Limited	Annual Limitation
		($ in millions)	
Net operating loss	$ 3,674	$ 1	$ 1
AMT net operating loss	$ 2,642	$ 1	$ 1

As of December 31, 2010, we do not believe that an ownership change has occurred. Future equity transactions by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

Accounting guidance for recognizing and measuring uncertain tax positions prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. As of December 31, 2010, the amount of unrecognized tax benefits related to AMT associated with uncertain tax positions was $34 million. As of December 31, 2009, the amount of unrecognized tax benefits related to regular tax liabilities and AMT associated with uncertain tax positions was $231 million. Of this amount, $87 million was related to regular tax liabilities and $144 million was related to AMT. If these unrecognized tax benefits are disallowed and we are required to pay additional AMT liabilities, any payments can be utilized as credits against future regular tax liabilities. The uncertain tax positions identified would not have a material effect on the effective tax rate. At December 31, 2010, we had an accrued liability of $8 million for interest related to these uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2010	2009	2008
		($ in millions)	
Unrecognized tax benefits at beginning of period	$ 231	$ 60	$ 133
Additions based on tax positions related to the current year		171	48
Reductions for tax positions of prior years	(197)		(120)
Settlements			(1)
Unrecognized tax benefits at end of period	$ 34	$ 231	$ 60

Chesapeake files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. With few exceptions, Chesapeake is no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years prior to 2007. The Internal Revenue Service (IRS) is currently examining Chesapeake s 2007, 2008 and 2009 U.S. income tax returns.

6. Related Party Transactions

Chief Executive Officer

As of December 31, 2010, we had accrued accounts receivable from our Chief Executive Officer, Aubrey K. McClendon, of $30 million representing joint interest billings from December 2010 which were invoiced and timely paid in January 2011. Since Chesapeake was founded in 1989, Mr. McClendon has acquired working interests in virtually all of our natural gas and oil properties by participating in our drilling activities under the terms of the Founder Well Participation Program (FWPP) and predecessor participation arrangements provided for in Mr. McClendon s employment agreements. Under the FWPP, approved by our shareholders in June 2005, Mr. McClendon may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake during a calendar year, but he is not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors not less than 30 days prior to the start of each calendar year. His participation is permitted only under the terms outlined in the FWPP, which, among other things, limits his individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of his participation. In addition, the company is reimbursed for costs associated with leasehold acquired by Mr. McClendon as a result of his well participation.

On December 31, 2008, we entered into a new five-year employment agreement with Mr. McClendon that contained a one-time well cost incentive award to him. The total cost of the award to Chesapeake was $75 million plus employment taxes in the amount of approximately $1 million. We are recognizing the incentive award as general and administrative expense over the five-year vesting period for the clawback described below, resulting in an expense of approximately $15 million per year beginning in 2009. In addition to state and federal income tax withholding, similar employment taxes were imposed on Mr. McClendon and withheld from the award. The net incentive award of approximately $44 million was fully applied against costs attributable to interests in company wells acquired by Mr. McClendon or his affiliates under the FWPP. The incentive award is subject to a clawback equal to any unvested portion of the award if during the initial five-year term of the employment agreement, Mr. McClendon resigns from the company or is terminated for cause by the company.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Related Parties

During 2010, our 42%-owned affiliate, Chesapeake Midstream Partners, L.P. (CHKM), provided us natural gas gathering and treating services in the ordinary course of business. In addition, there are agreements in place whereby we support CHKM in various functions for which we are reimbursed. During 2010, our transactions with CHKM included the following:

	Year Ended December 31, 2010 ($ in millions)	
Amounts paid to CHKM:		
Gas gathering fees	$	378
Amounts received from CHKM:		
Compressor rentals		48
Inventory purchases		47
Other services provided[a]		73
Total amounts received from CHKM	$	168

(a) Includes amounts received related to the General and Administrative Services and Reimbursement Agreement, the Employee Secondment Agreement, the Shared Services Agreement and the Additional Services and Reimbursement Agreement agreed to at the formation of the joint venture.

As of December 31, 2010, we had a net payable to CHKM of $45 million.

During 2010 and 2009, our 26%-owned affiliate, Frac Tech Holdings, LLC, provided us hydraulic fracturing and other services in the ordinary course of business. During 2010 and 2009, we paid Frac Tech $89 million and $43 million, respectively, for these services. As of December 31, 2010 and 2009 we had $30 million and $8 million, respectively, due Frac Tech for services provided and not yet paid.

7. Employee Benefit Plans

Our qualified 401(k) profit sharing plan (401(k) Plan) is the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except certain employees of Chesapeake Appalachia, L.L.C. Eligible employees may elect to defer compensation through voluntary contributions to their 401(k) Plan accounts, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches employee contributions dollar for dollar (subject to a maximum contribution of 15% of an employee s annual salary and bonus compensation) with Chesapeake common stock purchased in the open market. The company contributed $54 million, $48 million and $40 million to the 401(k) Plan in 2010, 2009 and 2008, respectively.

Chesapeake also maintains a nonqualified deferred compensation plan, the Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan (DC Plan). Prior to 2009, to be eligible to participate in the DC Plan, an employee must have received annual compensation (base salary and bonus combined in the prior 12 months) of at least $100,000, had a minimum of one year of service as a company employee and have made the maximum contribution allowable under the 401(k) Plan. For employees with at least five years of service as a company employee, the company matched employee contributions to the plan in Chesapeake common stock. On January 1, 2009, the plan was amended to allow for participation for any employees who received compensation (base salary only) of at least $150,000 and had an employment agreement with the company. In addition, in 2009 and 2010 the company matched employee contributions with Chesapeake common stock once the employee had at least three years of service as a company employee. Chesapeake matches 100% of employee contributions up to 15% of base salary and bonus in the aggregate for the DC Plan. In 2011, the company began matching contributions immediately upon an employee s participation in the DC Plan. The maximum compensation that can be deferred by employees under all company deferred compensation plans, including the Chesapeake 401(k) plan, is a total of 75% of base salary and 100% of performance bonus. We contributed $9 million, $7 million and $6 million to the DC Plan during 2010, 2009 and 2008, respectively, to fund the match. The company s non-employee directors are able to defer up to 100% of director fees into the DC Plan.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Any assets placed in trust by Chesapeake to fund future obligations of the company s nonqualified deferred compensation plans are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Chesapeake maintains no post-employment benefit plans except those sponsored by its wholly owned subsidiary, Chesapeake Appalachia, L.L.C. Participation in these plans is limited to existing employees who are union members and former employees who were union members. The Chesapeake Appalachia, L.L.C. benefit plans provide health care and life insurance benefits to eligible employees upon retirement. We account for these benefits on an accrual basis. As of December 31, 2010, the company had accrued approximately $2 million in accumulated post-employment benefit liability.

8. Stockholders Equity and Stock-Based Compensation Plans

Common Stock

The following is a summary of the changes in our common shares outstanding for 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Shares issued at January 1	648,549	607,953	511,648
Convertible note exchanges	299	10,210	23,913
Preferred stock conversions/exchanges	21	1,422	12,673
Restricted stock issuances (net of forfeitures)	5,924	3,633	4,708
Stock option exercises	458	508	1,584
Common stock issued for the purchase of proved and unproved properties		24,823	1,677
Common stock issuances for cash			51,750
Shares issued at December 31	655,251	648,549	607,953

In 2009 and 2008, we issued 24,822,832 and 1,677,000 shares of common stock, valued at $429 million and $34 million, respectively, for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

In 2010, 2009 and 2008, holders of certain of our contingent convertible senior notes exchanged their notes for shares of common stock in privately negotiated exchanges as summarized below:

Year	Contingent Convertible Senior Notes	Principal Amount ($ in millions)	Number of Common Shares Issued (in thousands)
2010	2.25% due 2038	$ 11	299
2009	2.25% due 2038	$ 364	10,210

2008	2.75% due 2035	$	239	8,841
	2.50% due 2037		272	8,417
	2.25% due 2038		254	6,655
		$	765	23,913

The difference between the allocated debt value of the notes that were exchanged and the fair value of the common stock issued resulted in a gain (loss) of ($2) million, ($40) million and $27 million, including deferred charges associated with the exchanges, on the cancellation of indebtedness for the years ended December 31, 2010, 2009 and 2008, respectively.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Preferred Stock

Following is a summary of our preferred stock, including the primary conversion terms as of December 31, 2010:

Preferred Stock Series	Issue Date	Liquidation Preference per Share	Holder s Conversion Right	Conversion Rate	Conversion Price	Company s Conversion Right From	Company s Market Conversion Trigger[(a)]
5.75% cumulative convertible non-voting	May and June 2010	$ 1,000	Any time	37.0370	$ 27.0000	May 17, 2015	$ 35.1000
5.75% (series A) cumulative convertible non-voting	May 2010	$ 1,000	Any time	35.7961	$ 27.9360	May 17, 2015	$ 36.3168
4.50% cumulative convertible	September 2005	$ 100	Any time	2.2727	$ 43.9998	September 15, 2010	$ 57.1997
5.00% cumulative convertible (series 2005B)	November 2005	$ 100	Any time	2.5707	$ 38.8993	November 15, 2010	$ 50.5691

(a) Convertible at the company s option if the trading price of the company s common stock equals or exceeds the trigger price for a specified time period or after the conversion date indicated if there are less than 250,000 shares of 4.50% or 5.00% (series 2005B) preferred stock outstanding or 25,000 shares of 5.75% or 5.75% (series A) preferred stock outstanding.

The following is a summary of the changes in our preferred shares outstanding for 2010, 2009 and 2008:

	5.75%	5.75%(A)	4.50%	5.00% (2005B)	5.00% (2005)	6.25%	4.125%
				(in thousands)			
Shares outstanding at January 1, 2010			2,559	2,096	5		
Preferred stock issuances	1,500	1,100					
Conversion/exchange of preferred for common stock					(5)		
Shares outstanding at December 31, 2010	1,500	1,100	2,559	2,096			

Shares outstanding at January 1, 2009	2,559	2,096	5	144	3
Conversion/exchange of preferred for common stock				(144)	(3)
Shares outstanding at December 31, 2009	2,559	2,096	5		
Shares outstanding at January 1, 2008	3,450	5,750	5	144	3
Conversion/exchange of preferred for common stock	(891)	(3,654)			
Shares outstanding at December 31, 2008	2,559	2,096	5	144	3

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2010, 2009 and 2008, shares of our cumulative convertible preferred stock were exchanged for or converted into shares of common stock as summarized below:

Year of Exchange/ Conversion	Cumulative Convertible Preferred Stock	Number of Preferred Shares	Number of Common Shares Issued	Type of Transaction
		(in thousands)		
2010	5.0% (series 2005)	5	21	Conversion
2009	6.25%	144	1,239	Conversion
	4.125%	3	183	Conversion
			1,422	
2008	5.0% (series 2005B)	3,654	10,443	Exchange
	4.5%	891	2,228	Exchange
	4.125%	(a)	2	Conversion
			12,673	

(a) Nominal amount.

In connection with the exchanges and conversions noted above, we recorded a loss of $67 million in 2008. There were no losses in 2010 and 2009. In general, the loss is equal to the excess of the fair value of all preferred stock exchanged over the fair value of the common stock issuable pursuant to the original terms of the preferred stock.

Dividends

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

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

Stock-Based Compensation Plans

Under Chesapeake s Long Term Incentive Plan, restricted stock, stock options, stock appreciation rights, performance shares and other stock awards may be awarded to employees, directors and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares of common stock available for awards under the plan may not exceed 37,500,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at specified dates or upon the satisfaction of certain performance or other criteria determined by a committee of the Board of Directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. There were 87,500 shares of restricted stock issued to our non-employee directors from this plan in each of 2010, 2009 and 2008. Additionally, there were

5.8 million, 4.0 million and 4.5 million restricted shares issued, net of forfeitures, to employees and consultants during 2010, 2009 and 2008, respectively, from this plan. As of December 31, 2010, there were 8.2 million shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares available for awards under the plan may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the Board of Directors. No awards may be granted under this plan after April 14, 2013. This plan has been approved by our

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

shareholders. There were 0.1 million, (0.4) million and 0.2 million restricted shares, net of forfeitures, issued during 2010, 2009 and 2008, respectively, from this plan. As of December 31, 2010, there were 0.5 million shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake s common stock are awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 100,000 shares. This plan has been approved by our shareholders. In each of 2010 and 2009, 10,000 shares of common stock were awarded to new directors from this plan. As of December 31, 2010, there were 40,000 shares remaining available for issuance under this plan.

In addition to the plans described above, we have stock options outstanding to employees under a number of employee stock option plans which are described below. All outstanding options under these plans were at-the-money when granted, with an exercise price equal to the closing price of our common stock on the date of grant and have a ten-year exercise period. These plans were terminated in prior years and therefore no shares remain available for stock option grants under the plans.

Name of Plan	Eligible Participants	Type of Options	Shares Covered	Shareholder Approved	Outstanding Options at December 31, 2010
2002 and 2001 Stock Option Plans	Employees and consultants	Incentive and nonqualified	3,000,000/ 3,200,000	Yes	499,263
2002 and 2001 Nonqualified Stock Option Plans	Employees and consultants	Nonqualified	4,000,000/ 3,000,000	No	807,865
2000 and 1999 Employee Stock Option Plans	Employees and consultants	Nonqualified	3,000,000 (each plan)	No	61,675
1996 and 1994 Stock Option Plans	Employees and consultants	Incentive and nonqualified	6,000,000/ 4,886,910	Yes	37,033

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is generally four years from the date of grant for employees and three years for non-employee directors. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized in general and administrative expenses, production expenses, marketing, gathering and compression expenses or service operations expense. Note 1 details the accounting for our stock-based compensation expense in 2010, 2009 and 2008.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the status of the unvested shares of restricted stock and changes during 2010, 2009 and 2008 is presented below:

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2010	19,225	$ 31.89
Granted	9,061	$ 24.19
Vested	(5,900)	$ 31.99
Forfeited	(1,011)	$ 30.05
Unvested shares as of December 31, 2010	21,375	$ 28.68
Unvested shares as of January 1, 2009	21,622	$ 38.85
Granted	8,019	$ 18.65
Vested	(9,214)	$ 36.38
Forfeited	(1,202)	$ 34.46
Unvested shares as of December 31, 2009	19,225	$ 31.89
Unvested shares as of January 1, 2008	19,689	$ 32.42
Granted	6,800	$ 51.14
Vested	(3,942)	$ 28.27
Forfeited	(925)	$ 37.33
Unvested shares as of December 31, 2008	21,622	$ 38.85

The aggregate intrinsic value of restricted stock vested during 2010 was approximately $136 million based on the stock price at the time of vesting.

As of December 31, 2010, there was $364 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 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 years ended December 31, 2010 and 2009, we recognized a reduction in tax benefits related to restricted stock of $15 million and $49 million, respectively. During the year ended December 31, 2008, we recognized an excess tax benefit related to restricted stock of $28 million. These amounts were recorded as an adjustment to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides information related to stock option activity for 2010, 2009 and 2008:

	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, 2010	2,283	$ 8.36		
Exercised	(475)	6.29		$ 8
Forfeited / Canceled				
Outstanding and exercisable at December 31, 2010	1,808	$ 8.90	2.03	$ 31
Shares authorized for future grants				
Outstanding at January 1, 2009	2,802	$ 8.13		
Exercised	(508)	7.12		$ 8
Forfeited / Canceled	(11)	6.47		
Outstanding and exercisable at December 31, 2009	2,283	$ 8.36	2.75	$ 40
Shares authorized for future grants				
Outstanding at January 1, 2008	4,445	$ 7.55		
Exercised	(1,639)	6.54		$ 66
Forfeited / Canceled	(4)	15.26		
Outstanding and exercisable at December 31, 2008	2,802	$ 8.13	3.59	$ 23
Shares authorized for future grants	5,763			

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

As of December 31, 2010, there was no remaining unrecognized compensation cost related to unvested stock options.

During the years ended December 31, 2010, 2009 and 2008, we recognized excess tax benefits related to stock options of $2 million, $1 million and $15 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2010:

Range of Exercise Prices		Number of Options (in thousands)	Weighted-Avg. Remaining Contractual Life in Years	Weighted-Avg. Exercise Price
$ 5.20	$ 5.20	226	1.56	$ 5.20
5.35	5.85	32	1.26	5.47
6.11	6.11	358	0.82	6.11
6.40	7.74	64	1.25	6.87
7.80	7.80	325	2.02	7.80
7.86	10.01	111	1.82	8.58
10.08	10.08	357	2.48	10.08
10.10	15.06	197	3.05	12.82
15.47	16.08	88	3.90	15.73
22.49	22.49	50	4.25	22.49
$ 5.20	$ 22.49	1,808	2.03	$ 8.90

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Financial Instruments and Hedging Activities

Natural Gas and Oil Derivatives

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and oil prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of December 31, 2010 and 2009, our natural gas and oil derivative instruments were comprised of the following types of instruments:

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

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

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

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

Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The estimated fair values of our natural gas and oil derivative instruments as of December 31, 2010 and 2009 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2010		December 31, 2009	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (bbtu):				
Fixed-price swaps	1,035,134	$ 1,307	492,053	$ 662
Call options	1,477,742	(701)	996,750	(541)
Put options	(51,220)	(59)	(69,620)	(50)
Fixed-price knockout swaps			38,370	17
Fixed-price collars			74,240	92
Basis protection swaps	173,691	(55)	125,469	(50)
Total natural gas	2,635,347	492	1,657,262	130
Oil (mbbl):				
Fixed-price swaps	4,385	(31)	5,475	3
Call options	64,226	(1,129)	14,975	(144)
Fixed-price knockout swaps	1,827	19	6,572	32
Total oil	70,438	(1,141)	27,022	(109)
Total estimated fair value		$ (649)		$ 21

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

The components of natural gas and oil sales for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Natural gas and oil sales	$ 4,248	$ 3,291	$ 7,069
Gains (losses) on natural gas and oil derivatives	1,422	1,722	879
Gains (losses) on ineffectiveness of cash flow hedges	(23)	36	(90)
Total natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858

Based upon the market prices at December 31, 2010, we expect to transfer approximately $15 million (net of income taxes) of gain included in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of December 31, 2010 are expected to mature by December 31, 2022.

We have a multi-counterparty hedge facility with 12 counterparties that have committed to provide approximately 5.6 tcfe of hedging capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. In February 2011, we amended the agreement for the hedge facility primarily to allow us to protect our natural gas liquids production from price volatility and to allow for greater flexibility when hedging our anticipated production. As of December 31, 2010, we had hedged a total of 2.9 tcfe of our future production under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas, natural gas liquids and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based hedging capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based hedging limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into hedges with the company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of December 31, 2010 and 2009, our interest rate derivative instruments were comprised of the following types of instruments:

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

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

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

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

The notional amount of debt hedged and the estimated fair value of our interest rate derivatives outstanding as of December 31, 2010 and 2009 are provided below.

	December 31, 2010		December 31, 2009	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 1,900	$ (54)	$ 2,925	$ (113)
Call options	250	(2)	250	(2)

Swaptions	500		(13)	500		(11)
Collars				250		(6)
Totals	$ 2,650	$	(69)	$ 3,925	$	(132)

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gains or (losses) from interest rate derivative transactions are reflected as adjustments to interest expense in the consolidated statements of operations. The components of interest expense for the years ended December 31, 2010, 2009 and 2008 are presented below.

	Years Ended December 31,		
	2010	2009	2008
	($ in millions)		
Interest expense on senior notes	$ 718	$ 765	$ 637
Interest expense on credit facilities	61	60	117
Capitalized interest	(716)	(633)	(585)
(Gains) losses on interest rate derivatives	(80)	(114)	79
Amortization of loan discount and other	36	35	23
Total interest expense	$ 19	$ 113	$ 271

Gains and losses related to terminated qualifying interest rate derivative transactions will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next ten years, we will recognize $34 million in gains related to such transactions.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge. The fair value of the cross currency swap is recorded on the consolidated balance sheet as a liability of $43 million at December 31, 2010. The euro-denominated debt in long-term debt has been adjusted to $796 million at December 31, 2010 using an exchange rate of $1.3269 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 consolidated balance sheets. Derivative instruments reflected as current in the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the respective balance sheet dates. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the fair value of each classification of derivative instrument as of December 31, 2010 and 2009 on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value December 31, 2010	Fair Value December 31, 2009
		($ in millions)	
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 307	$ 417
Commodity contracts	Long-term derivative instruments	12	36
Foreign currency contracts	Long-term derivative instruments		43
Total		319	496
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	921	318
Commodity contracts	Long-term derivative instruments	229	66
Total		1,150	384
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(59)	(1)
Interest rate contracts	Long-term derivative instruments	(25)	(11)
Foreign currency contracts	Long-term derivative instruments	(43)	
Total		(127)	(12)
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(222)	(42)
Commodity contracts	Long-term derivative instruments	(1,837)	(768)
Interest rate contracts	Short-term derivative instruments	(15)	(27)
Interest rate contracts	Long-term derivative instruments	(29)	(94)
Total		(2,103)	(931)
Total derivative instruments		$ (761)	$ (63)

A consolidated summary of the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2010 and 2009 is provided below, separating fair value, cash flow and non-qualifying derivatives.

The following table presents the gain (loss) recognized in net income (loss) for instruments designated as fair value derivatives:

Fair Value Derivatives	Location of Gain (Loss)	Years Ended December 31, 2010	2009
		($ in millions)	
Interest rate contracts	Interest expense[a]	$ 20	$ 37

(a) Interest expense on items hedged for the years ended December 31, 2010 and 2009 was $19 million and $71 million, respectively, which is included in interest expense on the consolidated statements of operations.

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The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) and recognized in net income (loss), including any hedge ineffectiveness, for derivative instruments designated as cash flow derivatives:

Cash Flow Derivatives	Location of Gain (Loss)	Years Ended December 31, 2010	2009
		($ in millions)	
Gain (Loss) Recognized in AOCI (Effective Portion)			
Commodity contracts	AOCI	$ 386	$ 958
Foreign exchange contracts	AOCI	(22)	96
		$ 364	$ 1,054
Gain (Loss) Reclassified from AOCI (Effective Portion)			
Commodity contracts	Natural gas and oil sales	$ 789	$ 1,425
		$ 789	$ 1,425
Gain (Loss) Recognized (Ineffective Portion and Amount Excluded from Effectiveness Testing)[a]			
Commodity contracts	Natural gas and oil sales	$ (19)	$ 193
		$ (19)	$ 193

(a) In the years ended December 31, 2010 and 2009, the amount of gain (loss) recognized in net income (loss) represents ($23) million and $36 million related to the ineffective portion of our cash flow derivatives and $4 million and $157 million, respectively, related to the amount excluded from the assessment of hedge effectiveness.

The following table presents the gain (loss) recognized in net income (loss) for instruments not qualifying as cash flow or fair value derivatives:

Non-Qualifying Derivatives	Location of Gain (Loss)	Years Ended December 31, 2010	2009
		($ in millions)	
Commodity contracts	Natural gas and oil sales	$ 629	$ 139
Interest rate contracts	Interest expense	60	77
	Total	$ 689	$ 216

Credit Risk

Derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. On December 31, 2010, our derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility described previously includes 12 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for all of our commodity hedging.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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10. Supplemental Disclosures About Natural Gas and Oil Producing Activities

Net Capitalized Costs

Evaluated and unevaluated capitalized costs related to Chesapeake s natural gas and oil producing activities are summarized as follows:

	December 31, 2010	December 31, 2009
	($ in millions)	
Natural gas and oil properties:		
Proved	$ 38,952	$ 35,007
Unproved	14,469	10,005
Total	53,421	45,012
Less accumulated depreciation, depletion and amortization	(25,595)	(24,220)
Net capitalized costs	$ 27,826	$ 20,792

Unproved properties not subject to amortization at December 31, 2010, 2009 and 2008 consisted mainly of leasehold acquired through corporate and significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $711 million, $627 million and $585 million of interest during 2010, 2009 and 2008, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unproved properties and seismic projects; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2010 and notes the year in which the associated costs were incurred:

	Year of Acquisition 2010	2009	2008	Prior	Total
			($ in millions)		
Leasehold acquisition cost	$ 5,619	$ 1,634	$ 3,992	$ 1,157	$ 12,402
Exploration cost	526	42	81	56	705
Capitalized interest	617	180	438	127	1,362
Total	$ 6,762	$ 1,856	$ 4,511	$ 1,340	$ 14,469

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Costs Incurred in Natural Gas and Oil Exploration and Development, Acquisitions and Divestitures

Costs incurred in natural gas and oil property exploration and development, acquisitions and divestitures activities which have been capitalized are summarized as follows:

	December 31,		
	2010	2009	2008
	($ in millions)		
Development and exploration costs:			
Development drilling[(a)]	$ 4,739	$ 2,729	$ 5,185
Exploratory drilling	691	651	612
Geological and geophysical costs[(b)(c)]	181	162	314
Asset retirement obligation and other	2	(2)	10
	5,613	3,540	6,121
Acquisition costs:			
Unproved properties[(d)]	6,953	2,793	8,250
Proved properties	243	61	355
Deferred income taxes			13
	7,196	2,854	8,618
Proceeds from divestitures:			
Unproved properties	(1,524)	(1,265)	(5,302)
Proved properties	(2,876)	(461)	(2,433)
	(4,400)	(1,726)	(7,735)
Total	$ 8,409	$ 4,668	$ 7,004

(a) Includes capitalized internal costs of $367 million, $337 million and $326 million, respectively.

(b) Includes capitalized internal costs of $16 million, $22 million and $26 million, respectively.

(c) Includes $24 million, $29 million and $25 million of related capitalized interest, respectively.

(d) Includes $687 million, $598 million and $561 million of related capitalized interest, respectively.

Results of Operations from Natural Gas and Oil Producing Activities (unaudited)

Chesapeake s results of operations from natural gas and oil producing activities are presented below for 2010, 2009 and 2008. The following table includes revenues and expenses associated directly with our natural gas and oil producing activities. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas and oil operations.

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Natural gas and oil sales	$ 5,647	$ 5,049	$ 7,858
Production expenses	(893)	(876)	(889)
Production taxes	(157)	(107)	(284)
Impairment of natural gas and oil properties		(11,000)	(2,800)
Depletion and depreciation	(1,394)	(1,371)	(1,970)
Imputed income tax provision[(a)]	(1,233)	3,114	(747)
Results of operations from natural gas and oil producing activities	$ 1,970	$ (5,191)	$ 1,168

(a) The imputed income tax provision is hypothetical (at the effective income tax rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

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Natural Gas and Oil Reserve Quantities (unaudited)

Chesapeake s petroleum engineers and independent petroleum engineering firms estimated all of our proved reserves as of December 31, 2010 and 2009. The independent petroleum engineering firms estimated an aggregate of 78% and 83% of our estimated proved reserves (by volume), as of December 31, 2010 and 2009, respectively, as set forth below.

	December 31.	
	2010	**2009**
Netherland, Sewell & Associates, Inc.	58%	59%
Lee Keeling and Associates, Inc.	7%	10%
Data and Consulting Services, Division of Schlumberger Technology Corporation	7%	7%
Ryder Scott Company L.P.	6%	7%

Chesapeake s petroleum engineers estimated all of our proved reserves as of December 31, 2008, and independent petroleum engineering firms audited an aggregate 76% of our estimated proved reserves (by volume), as set forth below. A reserve audit is not the same as a financial audit and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimates of reserves.

	December 31, 2008
Netherland, Sewell & Associates, Inc.	42%
Lee Keeling and Associates, Inc.	13%
Data and Consulting Services, Division of Schlumberger Technology Corporation	8%
Ryder Scott Company L.P.	8%
LaRoche Petroleum Consultants, Ltd.	5%

Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. Based on reserve reporting rules effective December 31, 2009, the price is calculated using the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Proved developed natural gas and oil reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

The information below on our natural gas and oil reserves is presented in accordance with regulations prescribed by the Securities and Exchange Commission as in effect as of the date of such estimates. Chesapeake emphasizes that reserve estimates are inherently imprecise. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

Presented below is a summary of changes in estimated reserves of Chesapeake for 2010, 2009 and 2008:

	Gas (bcf)	Oil (mmbbl)	Total (bcfe)
December 31, 2010			
Proved reserves, beginning of period	13,510	124.0	14,254
Extensions, discoveries and other additions	4,678	70.0	5,098
Revisions of previous estimates	(445)	104.6	183
Production	(925)	(18.4)	(1,035)
Sale of reserves-in-place	(1,426)	(11.2)	(1,493)
Purchase of reserves-in-place	63	4.4	89
Proved reserves, end of period	15,455	273.4	17,096
Proved developed reserves:			
Beginning of period	7,859	78.8	8,331
End of period	8,246	149.3	9,143
December 31, 2009			
Proved reserves, beginning of period	11,327	120.6	12,051
Extensions, discoveries and other additions	4,530	27.1	4,693
Revisions of previous estimates	(1,335)	(10.3)	(1,397)
Production	(835)	(11.8)	(906)
Sale of reserves-in-place	(209)	(1.8)	(220)
Purchase of reserves-in-place	32	0.2	33
Proved reserves, end of period	13,510	124.0	14,254
Proved developed reserves:			
Beginning of period	7,582	84.9	8,091
End of period	7,859	78.8	8,331
December 31, 2008			
Proved reserves, beginning of period	10,137	123.6	10,879
Extensions, discoveries and other additions	1,526	11.5	1,595
Revisions of previous estimates	957	(1.2)	950

Production	(775)	(11.2)	(843)
Sale of reserves-in-place	(674)	(4.6)	(702)
Purchase of reserves-in-place	156	2.5	172
Proved reserves, end of period	11,327	120.6	12,051
Proved developed reserves:			
Beginning of period	6,409	88.8	6,942
End of period	7,582	84.9	8,091

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2010, Chesapeake acquired approximately 89 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $243 million (primarily in 5 separate transactions of greater than $10 million each), and we sold 1.493 tcfe of our proved reserves for approximately $2.876 billion including divestitures related to three volumetric production payment transactions, the sale of a portion of our Barnett Shale assets and other non-core asset sales. During 2010, we recorded positive revisions of 183 bcfe to the December 31, 2009 estimates of our reserves. Included in the revisions were 189 bcfe of positive revisions resulting from higher natural gas prices as of December 31, 2010 and 6 bcfe of downward revisions resulting from changes to previous estimates. Higher prices extend the economic lives of the underlying natural gas and oil properties and thereby increase the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2010 were $4.38 per mcf and $79.42 per barrel before price differentials.

During 2009, Chesapeake acquired approximately 33 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $61 million (primarily in two separate transactions of greater than $10 million each) and we sold 220 bcfe of our proved reserves for approximately $576 million. During 2009, we recorded downward revisions of 1.397 tcfe to the December 31, 2008 estimates of our reserves. Included in the revisions were 952 bcfe of downward revisions resulting from lower natural gas prices using the average 12-month price in 2009 compared to the spot price as of December 31, 2008, and 445 bcfe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2009 were $3.87 per mcf and $61.14 per barrel before price differentials.

During 2008, Chesapeake acquired approximately 172 bcfe of proved reserves through purchases of natural gas and oil properties for consideration of $355 million (primarily in five separate transactions of greater than $10 million each) and we sold 702 bcfe of our proved reserves for approximately $2.433 billion. During 2008, we recorded positive revisions of 950 bcfe to the December 31, 2007 estimates of our reserves. Included in the revisions were 298 bcfe of negative adjustments caused by lower natural gas and oil prices at December 31, 2008 compared to prices at December 31, 2007 and 1.248 tcfe of positive performance related revisions. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The natural gas and oil prices used in computing our reserves as of December 31, 2008 were $5.71 per mcf and $44.61 per barrel before price differentials.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Accounting Standards Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2010 and 2009, were determined by applying the trailing average 12-month prices and year-end costs to the estimated quantities of natural gas and oil to be produced. Actual future prices and costs may be materially higher or lower than the 12-month average prices and year-end costs used. Amounts as of December 31, 2008 were determined using year-end prices and costs. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year. Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

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The following summary sets forth our future net cash flows relating to proved natural gas and oil reserves based on the standardized measure:

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Future cash inflows	$ 69,616[a]	$ 49,322[b]	$ 62,995[c]
Future production costs	(20,384)	(16,620)	(18,828)
Future development costs	(11,602)	(8,881)	(7,378)
Future income tax provisions	(6,859)	(4,106)	(9,813)
Future net cash flows	30,771	19,715	26,976
Less effect of a 10% discount factor	(17,588)	(11,512)	(15,143)
Standardized measure of discounted future net cash flows	$ 13,183	$ 8,203	$ 11,833

(a) Calculated using prices of $4.38 per mcf of natural gas and $79.42 per barrel of oil, before field differentials.

(b) Calculated using prices of $3.87 per mcf of natural gas and $61.14 per barrel of oil, before field differentials.

(c) Calculated using prices of $5.71 per mcf of natural gas and $44.61 per barrel of oil, before field differentials.

The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	Years Ended December 31,		
	2010	2009	2008
		($ in millions)	
Standardized measure, beginning of period[a]	$ 8,203	$ 11,833	$ 14,962
Sales of natural gas and oil produced, net of production costs[b]	(3,199)	(2,307)	(5,896)
Net changes in prices and production costs	3,337	(7,297)	(5,025)
Extensions and discoveries, net of production and development costs	5,580	2,374	2,752
Changes in future development costs	173	1,910	1,043
Development costs incurred during the period that reduced future development costs	717	650	1,130
Revisions of previous quantity estimates	199	(1,290)	1,524
Purchase of reserves-in-place	255	41	362
Sales of reserves-in-place	(2,235)	(377)	(1,696)
Accretion of discount	945	1,560	2,057
Net change in income taxes	(716)	2,521	1,843
Changes in production rates and other	(76)	(1,415)	(1,223)
Standardized measure, end of period[a]	$ 13,183	$ 8,203	$ 11,833

(a) The impact of cash flow hedges has not been included in any of the periods presented.

(b) Excluding gains (losses) on derivatives.

11. Divestitures

Industry Participation Agreements

As of December 31, 2010, we had entered into five significant industry participation agreements to sell a portion of our leasehold in certain areas, which allowed us to recover much or all of our initial leasehold investments in the plays, reduce our ongoing capital costs, reduce future DD&A expense and reduce future risks. The transactions are detailed below.

On November 16, 2010, we entered into an industry participation agreement with a wholly owned U.S. subsidiary of CNOOC Limited (CNOOC) to develop our Eagle Ford Shale leasehold in South Texas. Under the terms of the agreement, CNOOC acquired a 33.3% undivided interest in approximately 600,000 net acres of our Eagle Ford Shale

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

leasehold along with 18.2 bcfe of estimated proved reserves. We received $1.12 billion in cash at closing, and CNOOC agreed to fund 75% of our share of drilling and completion costs in the Eagle Ford Shale until an additional $1.08 billion has been paid, which we expect to occur by year-end 2012. In addition, CNOOC has the right to a 33.3% participation in any additional leasehold we acquire in the Eagle Ford Shale at cost plus a fee.

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

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

On September 5, 2008, we entered into an industry participation agreement with BP America Inc. to develop our Fayetteville Shale leasehold in Arkansas. Under the terms of the industry participation agreement, BP acquired a 25% undivided interest in approximately 540,000 net acres of our Fayetteville Shale leasehold along with 161.8 bcfe of estimated proved reserves. We received $1.1 billion in cash at closing, and BP paid an additional $800 million by funding 100% of Chesapeake s 75% share of drilling and completion costs during 2008 and 2009. In addition, BP has the right to a 25% participation in any additional leasehold we acquire in the Fayetteville Shale at cost plus a fee.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2010, 2009 and 2008, our drilling and completion costs included the benefit of approximately $1.151 billion, $1.153 billion and $271 million, respectively, in drilling and completion carries associated with our industry participation agreements with CNOOC, Total, Statoil, BP and PXP as follows:

Shale Play	Industry Participation Agreement Partner	Industry Participation Agreement Date	Years Ended December 31, 2010	2009	2008
			($ in millions)		
Eagle Ford	CNOOC	November 2010	$ 67	$	$
Barnett	Total	January 2010	483		
Marcellus	Statoil	November 2008	601	162	
Fayetteville	BP	September 2008		601	199
Haynesville	PXP	July 2008		390	72
			$ 1,151	$ 1,153	$ 271

During 2010, 2009 and 2008, as part of our industry participation agreements with Total, Statoil and PXP, we sold interests in additional leasehold in the Barnett, Marcellus and Haynesville shale plays for approximately $440 million, $100 million and $40 million, respectively.

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.

Volumetric Production Payments

From time to time, we choose to monetize certain of our producing assets in our more mature producing regions. We retain drilling rights on the properties below currently producing intervals and outside of producing well bores.

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

Date of VPP	Region	Proceeds ($ in millions)	Proved Reserves (bcfe) (at time of sale)	$ / mcfe	Original Term (years)
September 2010	Barnett Shale	$ 1,150	390	$ 2.93	5
June 2010	Permian Basin	$ 335	38	$ 8.73	10
February 2010	East Texas and the Texas Gulf Coast	$ 180	46	$ 3.95	10
August 2009	South Texas	$ 370	68	$ 5.46	7.5
December 2008	Anadarko and Arkoma Basins	$ 412	98	$ 4.19	8
August 2008	Anadarko Basin	$ 600	93	$ 6.38	11

May 2008	Texas, Oklahoma and Kansas	$	622	94	$	6.53	11
December 2007	Kentucky and West Virginia	$	1,100	208	$	5.29	15

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.

Sale of Springridge Gathering System

On December 21, 2010, our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., sold its Springridge natural gas gathering system and related facilities in the Haynesville Shale to our 42.5%-owned affiliate, Chesapeake Midstream Partners, L.P. (NYSE: CHKM) for $500 million and recorded a gain on the sale of $157 million. In connection with this transaction, CHKM and certain Chesapeake subsidiaries entered into ten-year gathering and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

compression agreements covering Chesapeake s upstream assets within an area of dedication around the existing pipeline system. The gathering and compression agreements are similar to the previously existing gathering agreement between Chesapeake and CHKM and includes a minimum volume commitment and periodic rate redetermination.

Other Divestitures

In 2010 and 2009, we sold non-core proved and unproved properties for proceeds of approximately $355 million and $450 million, respectively.

12. Investments

At December 31, 2010 and 2009, we had the following investments:

	Approximate % Owned	Accounting Method	Carrying Value December 31, 2010	2009
			($ in millions)	
Chesapeake Midstream Partners, L.P.	42%	Equity	$ 695	$
Frac Tech Holdings, LLC.	26%	Equity	311	239
Chaparral Energy, Inc.	20%	Equity	133	103
Gastar Exploration Ltd.	11%	Cost	29	32
Other		Cost/Equity	40	30
			$ 1,208	$ 404

Chesapeake Midstream Partners, L.P. On September 30, 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, Chesapeake contributed certain natural gas gathering and processing assets to, and GIP purchased a 50% interest in, a new joint venture entity. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. During the fourth quarter of 2009, the joint venture was consolidated within our financial statements. Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we changed the accounting for our investment in the joint venture to the equity method. Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our consolidated statement of equity for the year ended December 31, 2010. This charge reflects the difference between the carrying value of our initial investment in the joint venture, which was recorded at carryover basis as an entity under common control, and the fair value of our equity in the joint venture as of the formation date.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), completed an initial public offering of 24,437,500 common units (including 3,187,500 common units issued pursuant to the exercise of the underwriters over-allotment option on August 3, 2010) representing limited partner interests and received gross offering proceeds of approximately $513 million at an initial offering price of $21.00 per unit less approximately $38 million for underwriting discounts and commissions, structuring fees and offering expenses. Pursuant to the terms of our contribution agreement with GIP, CHKM distributed the approximate $62 million of net proceeds from the exercise of the over-allotment option to GIP on August 3, 2010. In connection with the closing of the offering, Chesapeake and GIP contributed the interests of the midstream joint venture s operating subsidiary to CHKM, and CHKM is continuing the business that had been conducted by the joint venture. Common units owned by public security holders represent 17.7% of all outstanding limited partner interests, and Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests. The limited partners, collectively, have a 98.0% interest in CHKM and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2.0% interest in CHKM.

During 2010, we recorded positive equity method adjustments of $89 million for our share of CHKM s income and recorded accretion adjustments of $14 million for our share of equity in excess of cost. As a result of the initial public offering by CHKM in 2010, we recognized a $90 million gain on our investment. The gain represented our proportionate share of the excess of offering proceeds over the carrying value of our investment in CHKM and is reported in earnings

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(losses) from equity investees on our statements of operations. The carrying value of our investment in CHKM is less than our underlying equity in net assets by approximately $237 million as of December 31, 2010. This difference is being accreted over 20 years.

In 2010, we received cash distributions of $88 million from CHKM and its predecessor.

Frac Tech Holdings, LLC. Frac Tech Holdings, LLC provides hydraulic fracturing and other services to oil and gas companies. In 2010, we made an additional $100 million investment in Frac Tech, recorded positive equity method adjustments of $55 million for our share of Frac Tech s income and recorded depreciation adjustments of $25 million for our cost in excess of equity. In addition, in November 2010 and December 2010, we received cash distributions of $52 million and $6 million, respectively, from Frac Tech. The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $153 million as of December 31, 2010. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech and is being amortized over the estimated life of the intangibles. We recently announced our intention to sell our interest in Frac Tech. The sale is subject to changes in market conditions and other factors, and there can be no assurance that we will complete the transaction on a timely basis or at all.

Chaparral Energy, Inc. Chaparral Energy, Inc. is an independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties. In 2010, we recorded positive equity method adjustments of $5 million for our share of Chaparral s income and depreciation adjustments of $6 million for our cost in excess of equity. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $58 million as of December 31, 2010. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate. In addition, as a result of an equity offering by Chaparral to a third party in April 2010, we recognized a $31 million gain on our investment in 2010. This gain represented our proportionate share of the excess of offering proceeds over the carrying value of our investment in Chaparral and is reported in earnings (losses) from equity investees on our statements of operations. Due to the dramatic decrease in natural gas and oil prices at the end of 2008 and into 2009 as a result of the slowing of the worldwide economy, on March 31, 2009 and December 31, 2008, we recognized an other than temporary impairment on our investment in Chaparral of $51 million and $100 million, respectively. We recently announced our intention to sell our investment in Chaparral. The sale is subject to changes in market conditions and other factors, and there can be no assurance that we will complete the transaction on a timely basis or at all.

Gastar Exploration Ltd. Gastar Exploration Ltd. (AMEX: GST) is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. During 2010, the common stock price of Gastar decreased from $4.79 per share to $4.30 per share. Due to the dramatic decrease in natural gas and oil prices at the end of 2008 and into 2009 as a result of the slowing of the worldwide economy, on March 31, 2009, we recognized an other than temporary impairment on our investment in Gastar of $70 million. Our investment in Gastar had a historical cost basis of $89 million as of December 31, 2010 and 2009.

Other. In 2010, we invested $20 million for a 40% equity interest in Twin Eagle Resource Management LLC, a natural gas trading and management firm. In 2010, we recorded a $16 million impairment of certain other equity investments. Our investees were impacted by the dramatic slowing of the worldwide economy and the tightening of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on March 31, 2009 and December 31, 2008 of $41 million and $80 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Restructuring Costs

In 2009, we restructured our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model the company uses elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the reorganization include termination benefits, consolidating or closing facilities and relocating employees. In addition, we had certain other workforce reductions that resulted in termination benefits. A summary of Chesapeake s restructuring costs is presented below:

	Year Ended December 31, 2009 ($ in millions)
Termination and relocation costs	$ 22
Acceleration of restricted stock awards	9
Other associated costs	3
Total Restructuring Costs	$ 34

14. Fair Value Measurements

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

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

Investments. The fair value of Chesapeake s investment in Gastar Exploration Ltd. (NYSE Amex: GST) common stock is based on a quoted market price.

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

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

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

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
			($ in millions)	
Financial Assets (Liabilities):				
Cash equivalents	$ 102	$	$	$ 102
Investments	29			29
Other long-term assets	52			52
Long-term debt			(1,371)	(1,371)
Other long-term liabilities	(52)			(52)
Derivatives:				
Commodity assets		1,364	105	1,469
Commodity liabilities		(59)	(2,059)	(2,118)
Interest rate liabilities			(69)	(69)
Foreign currency liabilities			(43)	(43)
Total derivatives		1,305	(2,066)	(761)
Total	$ 131	$ 1,305	$ (3,437)	$ (2,001)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2009:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
			($ in millions)	
Financial Assets (Liabilities):				
Cash equivalents	$ 307	$	$	$ 307
Investments	32			32
Other long-term assets	34			34
Long-term debt			(1,398)	(1,398)
Other long-term liabilities	(34)			(34)
Derivatives:				
Commodity assets		693	143	836
Commodity liabilities		(1)	(809)	(810)

Interest rate liabilities			(132)	(132)
Foreign currency assets			43	43
Total derivatives		692	(755)	(63)
Total	$ 339	$ 692	$ (2,153)	$ (1,122)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during 2010 and 2009 is presented below:

	Derivatives Commodity	Interest Rate	Foreign Currency	Debt
	($ in millions)			
Beginning Balance as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses) (realized/unrealized):				
Included in earnings (realized)[a]	378	14		
Included in earnings or change in net assets (unrealized)[a]	(1,492)	46	(63)	77
Included in other comprehensive income (loss)	(25)		(23)	
Purchases, issuances and settlements	(149)	3		(50)[b]
Transfers in and out of Level 3				
Ending Balance as of December 31, 2010	$ (1,954)	$ (69)	$ (43)	$ (1,371)
Beginning Balance as of January 1, 2009	$ 432	$ (63)	$ (77)	$ (1,470)
Total gains (losses) (realized/unrealized):				
Included in earnings (realized)[a]	879	23		
Included in earnings or change in net assets (unrealized)[a]	(988)	91	25	(128)
Included in other comprehensive income (loss)	28		95	
Purchases, issuances and settlements	(1,017)	(183)		200[b]
Transfers in and out of Level 3				
Ending Balance as of December 31, 2009	$ (666)	$ (132)	$ 43	$ (1,398)

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

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

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock primarily using quoted market prices. Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	December 31, 2010		December 31, 2009	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 12,631	$ 13,272	$ 12,226	$ 12,824
Convertible preferred stock	$ 3,065	$ 3,019	$ 466	$ 401

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Asset Retirement Obligations

The components of the change in our asset retirement obligations are shown below.

	Years Ended December 31, 2010	2009
	($ in millions)	
Asset retirement obligations, beginning of period	$ 282	$ 269
Additions	16	14
Revisions		(3)
Settlements and disposals	(12)	(15)
Accretion expense	15	17
Asset retirement obligations, end of period	$ 301	$ 282

16. Major Customers and Segment Information

There were no sales to individual customers constituting 10% or more of total revenues (before the effects of hedging) for the year ended December 31, 2010. Major customers for the years ended December 31, 2009 and 2008 were as follows:

Year Ended December 31,	Customer	Amount ($ in millions)	Percent of Total Revenues
2009	EDF Trading North America LLC	$ 571	10%
2008	Eagle Energy Partners I, L.P.	$ 1,283	12%

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas and oil related to Chesapeake s ownership interests by the marketing, gathering and compression segment are reflected as exploration and production revenues. Such amounts totaled $4.0 billion, $2.9 billion and $5.5 billion for 2010, 2009 and 2008, respectively. The following tables present selected financial information for Chesapeake s operating segments.

	Exploration and Production	Marketing, Gathering and Compression	Other Operations ($ in millions)	Intercompany Eliminations	Consolidated Total
For the Year Ended December 31, 2010:					
Revenues	$ 5,647	$ 7,433	$ 757	$ (4,471)	$ 9,366
Intersegment revenues		(3,954)	(517)	4,471	
Total revenues	5,647	3,479	240		9,366
Depreciation, depletion and amortization	1,546	44	93	(69)	1,614
Other income (expense)	14	2			16
Interest expense	(13)	(6)			(19)
Impairment of investments	(16)				(16)
(Gains) losses on sale of other property and equipment	2	(139)			(137)
Other impairments		20	1		21
Losses on redemptions or exchanges of debt	(129)				(129)
Earnings (losses) from equity investees	34	193			227
INCOME (LOSS) BEFORE INCOME TAXES	$ 2,561	$ 362	$ (29)	$ (10)	$ 2,884
TOTAL ASSETS	$ 33,632	$ 3,458	$ 854	$ (765)	$ 37,179
NET CAPITAL EXPENDITURES	$ 8,671	$ (2,011)(a)	$ 269	$	$ 6,929

(a) Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we ceased consolidating our midstream joint venture with Global Infrastructure Partners within our financial statements.

	Exploration and Production	Marketing, Gathering and Compression	Other Operations	Intercompany Eliminations	Consolidated Total
For the Year Ended December 31, 2009:					
Revenues	$ 5,049	$ 5,341	$ 414	$ (3,102)	$ 7,702
Intersegment revenues		(2,878)	(224)	3,102	
Total revenues	5,049	2,463	190		7,702
Depreciation, depletion and amortization	1,556	44	50	(35)	1,615
Other income (expense)	9	3	1	(2)	11
Interest expense	(113)	(1)		1	(113)

Impairment of natural gas and oil properties	11,000				11,000
Impairment of investments	(162)				(162)
(Gains) losses on sale of other property and equipment		38			38
Other impairments	13	90	27		130
Losses on redemptions or exchanges of debt	(40)				(40)
Earnings (losses) from equity investees	(39)				(39)
INCOME (LOSS) BEFORE INCOME TAXES	$ (9,173)	$ (48)	$ (70)	$ 3	$ (9,288)
TOTAL ASSETS	$ 25,637	$ 4,323	$ 660	$ (706)	$ 29,914
NET CAPITAL EXPENDITURES	$ 4,837	$ 966	$ 290	$	$ 6,093

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Exploration and Production	Marketing, Gathering and Compression	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in millions)		
For the Year Ended December 31, 2008:					
Revenues	$ 7,858	$ 9,126	$ 631	$ (5,986)	$ 11,629
Intersegment revenues		(5,528)	(458)	5,986	
Total revenues	7,858	3,598	173		11,629
Depreciation, depletion and amortization	2,108	28	35	(27)	2,144
Other income (expense)	27	6		(6)	27
Interest expense	(271)	(2)		2	(271)
Impairment of natural gas and oil properties	2,800				2,800
Impairment of investments	(180)				(180)
Other impairments		30			30
Losses or redemptions on exchanges of debt	(4)				(4)
Earnings (losses) from equity investees	(38)				(38)
INCOME (LOSS) BEFORE INCOME TAXES	$ 968	$ 28	$ 82	$ (87)	$ 991
TOTAL ASSETS	$ 35,415	$ 3,416	$ 465	$ (703)	$ 38,593
NET CAPITAL EXPENDITURES	$ 7,658	$ 1,765	$ 229	$	$ 9,652

17. 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 midstream subsidiary, CMD, is not a guarantor and is subject to covenants in the midstream revolving bank credit facility referred to in Note 3 that restricts it from paying dividends or distributions or making loans to Chesapeake.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 2	$ 100	$	$ 102
Other	7	3,065	123	(31)	3,164
Total Current Assets	7	3,067	223	(31)	3,266
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		27,822	4		27,826
Other property and equipment, net		3,230	1,322		4,552
Total Property and Equipment		31,052	1,326		32,378
Other assets	166	669	700		1,535
Investments in subsidiaries and intercompany advance	1,217	263		(1,480)	
TOTAL ASSETS	$ 1,390	$ 35,051	$ 2,249	$ (1,511)	$ 37,179
CURRENT LIABILITIES:					
Current liabilities	$ 302	$ 4,082	$ 137	$ (31)	$ 4,490
Intercompany payable (receivable) from parent	(23,664)	21,939	1,612	113	
Total Current Liabilities	(23,362)	26,021	1,749	82	4,490
LONG-TERM LIABILITIES:					
Long-term debt, net	8,934	3,612	94		12,640
Deferred income tax liabilities	482	1,879	136	(113)	2,384
Other liabilities	72	2,322	7		2,401
Total Long-Term Liabilities	9,488	7,813	237	(113)	17,425

EQUITY:					
Chesapeake stockholders equity	15,264	1,217	263	(1,480)	15,264
Noncontrolling interest					
Total Equity	15,264	1,217	263	(1,480)	15,264
TOTAL LIABILITIES AND EQUITY	$ 1,390	$ 35,051	$ 2,249	$ (1,511)	$ 37,179

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 293	$ 14	$	$ 307
Other	27	2,031	166	(85)	2,139
Total Current Assets	27	2,324	180	(85)	2,446
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		20,788	4		20,792
Other property and equipment, net		2,903	3,015		5,918
Total Property and Equipment		23,691	3,019		26,710
Other assets	197	541	20		758
Investments in subsidiaries and intercompany advance	3,029	262		(3,291)	
TOTAL ASSETS	$ 3,253	$ 26,818	$ 3,219	$ (3,376)	$ 29,914
CURRENT LIABILITIES:					
Current liabilities	$ 277	$ 2,261	$ 235	$ (85)	$ 2,688
Intercompany payable (receivable) from parent	(19,388)	17,572	1,729	87	
Total Current Liabilities	(19,111)	19,833	1,964	2	2,688
LONG-TERM LIABILITIES:					
Long-term debt, net	10,359	1,892	44		12,295
Deferred income tax liabilities	393	704	49	(87)	1,059
Other liabilities	168	1,360	3		1,531
Total Long-Term Liabilities	10,920	3,956	96	(87)	14,885
EQUITY:					
Chesapeake stockholders equity	11,444	3,029	262	(3,291)	11,444
Noncontrolling interest			897		897
Total Equity	11,444	3,029	1,159	(3,291)	12,341

TOTAL LIABILITIES AND EQUITY	$	3,253	$	26,818	$	3,219	$	(3,376)	$	29,914

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 5,647	$	$	$ 5,647
Marketing, gathering and compression sales		3,368	248	(137)	3,479
Service operations revenue		240			240
Total Revenues		9,255	248	(137)	9,366
OPERATING COSTS:					
Production expenses		893			893
Production taxes		157			157
General and administrative expenses	2	421	30		453
Marketing, gathering and compression expenses		3,293	125	(66)	3,352
Service operations expense		208			208
Natural gas and oil depreciation, depletion and amortization		1,394			1,394
Depreciation and amortization of other assets		170	50		220
(Gains) losses on sales of other property and equipment		2	(139)		(137)
Other impairments		1	20		21
Total Operating Costs	2	6,539	86	(66)	6,561
INCOME (LOSS) FROM OPERATIONS	(2)	2,716	162	(71)	2,805
OTHER INCOME (EXPENSE):					
Interest expense	(637)	(99)	(1)	718	(19)
Earnings (losses) from equity investees		34	193		227
Losses on redemptions or exchanges of debt	(129)				(129)
Impairment of investments		(16)			(16)
Other income (expense)	718	11	5	(718)	16
Equity in net earnings of subsidiary	1,805	177		(1,982)	
Total Other Income (Expense)	1,757	107	197	(1,982)	79
INCOME (LOSS) BEFORE INCOME TAXES	1,755	2,823	359	(2,053)	2,884
INCOME TAX EXPENSE (BENEFIT)	(19)	1,018	138	(27)	1,110

NET INCOME (LOSS)	$	1,774	$	1,805	$	221	$	(2,026)	$	1,774

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 5,049	$	$	$ 5,049
Marketing, gathering and compression sales		2,181	510	(228)	2,463
Service operations revenue		190			190
Total Revenues		7,420	510	(228)	7,702
OPERATING COSTS:					
Production expenses		877	(1)		876
Production taxes		107			107
General and administrative expenses		318	31		349
Marketing, gathering and compression expenses		2,125	201	(10)	2,316
Service operations expense		182			182
Natural gas and oil depreciation, depletion and amortization		1,371			1,371
Depreciation and amortization of other assets		149	95		244
Impairment of natural gas and oil properties		11,000			11,000
(Gains) losses on sales of other property and equipment			38		38
Other impairments		40	90		130
Restructuring costs		34			34
Total Operating Costs		16,203	454	(10)	16,647
INCOME (LOSS) FROM OPERATIONS		(8,783)	56	(218)	(8,945)
OTHER INCOME (EXPENSE):					
Interest expense	(652)	(145)	(1)	685	(113)
Earnings (losses) from equity investees		(39)			(39)
Losses on redemptions or exchanges of debt	(40)				(40)
Impairment of investments		(162)			(162)

Other income (expense)	685	53	(42)	(685)	11
Equity in net earnings of subsidiary	(5,826)	(153)		5,979	
Total Other Income (Expense)	(5,833)	(446)	(43)	5,979	(343)
INCOME (LOSS) BEFORE INCOME TAXES	(5,833)	(9,229)	13	5,761	(9,288)
INCOME TAX EXPENSE (BENEFIT)	(3)	(3,403)	5	(82)	(3,483)
NET INCOME (LOSS)	(5,830)	(5,826)	8	5,843	(5,805)
Net (income) loss attributable to noncontrolling interest			(25)		(25)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (5,830)	$ (5,826)	$ (17)	$ 5,843	$ (5,830)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2008

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 7,858	$	$	$ 7,858
Marketing, gathering and compression sales		3,420	333	(155)	3,598
Service operations revenue		173			173
Total Revenues		11,451	333	(155)	11,629
OPERATING COSTS:					
Production expenses		890	(1)		889
Production taxes		284			284
General and administrative expenses		364	13		377
Marketing, gathering and compression expenses		3,363	142		3,505
Service operations expense		143			143
Natural gas and oil depreciation, depletion and amortization		1,970			1,970
Depreciation and amortization of other assets	14	129	48	(17)	174
Impairment of natural gas and oil properties		2,800			2,800
Other impairments			30		30
Total Operating Costs	14	9,943	232	(17)	10,172
INCOME (LOSS) FROM OPERATIONS	(14)	1,508	101	(138)	1,457
OTHER INCOME (EXPENSE):					
Interest expense	(630)	(197)	(2)	558	(271)
Earnings (losses) from equity investees		(38)			(38)
Losses on redemptions or exchanges of debt	(4)				(4)
Impairment of investments		(180)			(180)
Other income (expense)	558	21	6	(558)	27
Equity in net earnings of subsidiary	659	(20)		(639)	

Total Other Income (Expense)	583	(414)	4	(639)	(466)
INCOME (LOSS) BEFORE INCOME TAXES	569	1,094	105	(777)	991
INCOME TAX EXPENSE (BENEFIT)	(35)	435	41	(54)	387
NET INCOME (LOSS)	$ 604	$ 659	$ 64	$ (723)	$ 604

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 4,758	$ 359	$	$ 5,117
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(12,187)			(12,187)
Proceeds from divestitures of natural gas and oil properties		4,292			4,292
Additions to other property and equipment		(561)	(765)		(1,326)
Other investing activities		329	659	(270)	718
Cash used in investing activities		(8,127)	(106)	(270)	(8,503)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		14,384	733		15,117
Payments on credit facilities borrowings		(12,664)	(639)		(13,303)
Proceeds from issuance of senior notes, net of offering costs	1,967				1,967
Proceeds from preferred stock, net of offering costs	2,562				2,562
Cash paid to redeem debt	(3,434)				(3,434)
Other financing activities	(339)	1,158	(277)	(270)	272
Intercompany advances, net	(756)	200	16	540	
Cash provided by (used in) financing activities		3,078	(167)	270	3,181
Net increase (decrease) in cash and cash equivalents		(291)	86		(205)
Cash and cash equivalents, beginning of period		293	14		307
Cash and cash equivalents, end of period	$	$ 2	$ 100	$	$ 102

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 4,512	$ (156)	$	$ 4,356
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(5,840)			(5,840)
Proceeds from divestitures of natural gas and oil properties		1,926			1,926
Additions to other property and equipment		(894)	(789)		(1,683)
Other investing activities		79	56		135
Cash used in investing activities		(4,729)	(733)		(5,462)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		6,933	828		7,761
Payments on credit facilities borrowings		(8,514)	(1,244)		(9,758)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Proceeds from sales of noncontrolling interest in midstream joint venture			588		588
Other financing activities	(276)	65	(62)		(273)
Intercompany advances, net	(1,070)	277	793		
Cash provided by financing activities		(1,239)	903		(336)
Net increase (decrease) in cash and cash equivalents		(1,456)	14		(1,442)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 293	$ 14	$	$ 307

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 2008

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$ 156	$ 5,719	$ 175	$ (693)	$ 5,357
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(14,697)			(14,697)
Proceeds from divestitures of natural gas and oil properties		7,670			7,670
Additions to other property and equipment		(1,759)	(1,314)		(3,073)
Other investing activities		135			135
Cash used in investing activities		(8,651)	(1,314)		(9,965)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		12,831	460		13,291
Payments on credit facilities borrowings		(11,307)			(11,307)
Proceeds from issuance of senior notes, net of offering costs	2,136				2,136
Proceeds from issuance of common stock, net of offering costs	2,598				2,598
Cash paid to redeem debt	(312)				(312)
Other financing activities	(202)	131	21		(50)
Intercompany advances, net	(4,376)	3,025	658	693	
Cash provided by (used in) financing activities	(156)	4,680	1,139	693	6,356
Net increase (decrease) in cash and cash equivalents		1,748			1,748
Cash and cash equivalents, beginning of period		1			1
	$	$ 1,749	$	$	$ 1,749

Cash and cash equivalents, end of period	

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2010 and 2009 are as follows ($ in millions except per share data):

	Quarters Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Total revenues	$ 2,798	$ 2,012	$ 2,581	$ 1,975
Gross profit[(a)]	$ 1,212	$ 447	$ 817	$ 329
Net income attributable to Chesapeake	$ 738	$ 255	$ 558	$ 223
Net income available to common stockholders	$ 732	$ 235	$ 515	$ 181
Net earnings per common share:				
Basic	$ 1.16	$ 0.37	$ 0.81	$ 0.29
Diluted	$ 1.14	$ 0.37	$ 0.75	$ 0.28

	Quarters Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Total revenues	$ 1,995	$ 1,673	$ 1,811	$ 2,222
Gross profit (loss)[(a)(b)]	$ (9,053)	$ 424	$ 397	$ (713)
Net income (loss) attributable to Chesapeake[(b)]	$ (5,740)	$ 243	$ 192	$ (524)
Net income (loss) available to common stockholders[(b)]	$ (5,746)	$ 237	$ 186	$ (530)
Net earnings (loss) per common share:				
Basic	$ (9.63)	$ 0.39	$ 0.30	$ (0.84)
Diluted	$ (9.63)	$ 0.39	$ 0.30	$ (0.84)

(a) Total revenue less operating costs.

(b) Includes a before-tax ceiling test write-down of $9.6 billion and $1.4 billion on our natural gas and oil properties for the quarters ended March 31, 2009 and December 31, 2009, respectively.

19. Recently Issued 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 February 2010, the FASB amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance in 2010.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance in 2010. Adoption had no impact on our financial position or results of operations. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective beginning on January 1, 2011, and we do not expect the implementation to have a material impact on our financial position or results of operations. See Note 14 for discussion regarding fair value measurements.

20. Subsequent Events

Fayetteville Shale Asset Sale

On February 21, 2011, we entered into a purchase and sale agreement with BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited, to sell all of our Fayetteville Shale assets in Central Arkansas for $4.75 billion in cash before certain deductions and standard closing adjustments. The assets include approximately 487,000 net

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

acres of leasehold and producing natural gas properties and midstream assets with approximately 420 miles of pipeline. In the Fayetteville Shale, our current net production is approximately 415 mmcfe per day. As part of the transaction, Chesapeake has agreed to provide essential services for up to one year for BHP Billiton s Fayetteville properties for an agreed-upon fee. Closing of the transaction is subject to customary conditions, including filings under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and with the Committee on Foreign Investment in the United States. Closing is expected to occur in the first half of 2011.

Niobrara Project Cooperation Agreement

On February 16, 2011, CNOOC International Limited, a wholly owned subsidiary of CNOOC Limited, purchased a 33.3% undivided interest in our 800,000 net natural gas and oil leasehold acres in the DJ and Powder River Basins in northeast Colorado and southeast Wyoming. The consideration for the transaction was $570 million in cash. In addition, CNOOC has agreed to fund 66.7% of our share of drilling and completion costs until an additional $697 million has been paid, which we expect to occur by year-end 2014. CNOOC also has the right to a 33.3% participation in any additional leasehold we acquire in the Niobrara Shale.

Senior Notes Issuance

On February 11, 2011, we issued $1.0 billion of 6.125% Senior Notes due 2021 in a registered public offering. We used the net proceeds of $977 million from the offering to repay indebtedness outstanding under our revolving bank credit facility.

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Schedule II

CHESAPEAKE ENERGY CORPORATION

VALUATION AND QUALIFYING ACCOUNTS

($ in millions)

Description	Balance at Beginning of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2010:					
Allowance for doubtful accounts	$ 24	$	$	$ (6)	$ 18
Valuation allowance for deferred tax assets	$	$	$	$	$
December 31, 2009:					
Allowance for doubtful accounts	$ 12	$ 12	$	$	$ 24
Valuation allowance for deferred tax assets	$	$	$	$	$
December 31, 2008:					
Allowance for doubtful accounts	$ 8	$ 4	$	$	$ 12
Valuation allowance for deferred tax assets	$	$	$	$	$

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ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

ITEM 9A. ***Controls and Procedures***

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2010, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2010, to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the company s internal control over financial reporting occurred during the quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, the company s internal control over financial reporting.

Management s Report on Internal Control Over Financial Reporting

Management s annual report on internal control over financial reporting and the audit report on our internal control over financial reporting of our independent registered public accounting firm are included in Item 8 of this report.

ITEM 9B. ***Other Information***

Not applicable.

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PART III

ITEM 10. ***Directors, Executive Officers and Corporate Governance***

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than May 2, 2011.

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than May 2, 2011.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than May 2, 2011.

ITEM 13. ***Certain Relationships and Related Transactions and Director Independence***

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than May 2, 2011.

ITEM 14. ***Principal Accountant Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than May 2, 2011.

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PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules***

(a) The following documents are filed as part of this report:

1. *Financial Statements*. Chesapeake s consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Financial Statements.

2. *Financial Statement Schedules*. Schedule II is included in Item 8 of this report with our consolidated financial statements. No other financial statement schedules are applicable or required.

3. *Exhibits*. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.5% Senior Notes due 2017.	8-K	001-13726	4.1	08/16/2005		
4.2*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.1.1	11/15/2005		
4.3*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% Contingent Convertible Senior Notes due 2035.	8-K	001-13726	4.1.2	11/15/2005		

4.4*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% Senior Notes due 2013.	8-K	001-13726	4.1	06/30/2006

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.5*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/06/2006		
4.6*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	05/15/2007		
4.7*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	05/29/2008		
4.8*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% Contingent Convertible Senior Notes due 2038.	8-K	001-13726	4.2	05/29/2008		
4.9*	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.5% Senior Notes due 2015.	8-K	001-13726	4.1	02/03/2009		
4.9.1*	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009, with respect to additional 9.5% Senior Notes due 2015.	8-K	001-13726	4.2	02/17/2009		
4.10*	Indenture dated as of August 2, 2010 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	08/03/2010		
4.10.1*	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010, with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.10.2*	Second Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010, with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010		
4.10.3*	Fifth Supplemental Indenture dated February 11, 2011 to Indenture dated as of August 2, 2010, with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		
4.12*	Eighth Amended and Restated Credit Agreement, dated as of December 2, 2010, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, The Royal Bank of Scotland plc and BNP Paribas, as Co-Syndication Agent, Credit Agricole Corporate and Investment Bank, as Documentation Agent, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	12/8/2010		
10.1.1	Chesapeake s 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2009		
10.1.2	Chesapeake s 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997		
10.1.3	Chesapeake s 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006		
10.1.4	Chesapeake s 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006		
10.1.5	Chesapeake s 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008		
10.1.6	Chesapeake s 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008		
10.1.7	Chesapeake s 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008		
10.1.8	Chesapeake s 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008		
10.1.9	Chesapeake s 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008		
10.1.10	Chesapeake s 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008		

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.1.11	Chesapeake s 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008		
10.1.12	Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008		
10.1.13	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.					X	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	06/17/2010		
10.1.14.1	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.					X	
10.1.14.2	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005		
10.1.15	Founder Well Participation Program.	DEF -14A	001-13726	B	04/29/2005		
10.2.1	Third Amended and Restated Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.1	05/11/2009		
10.2.2	Amended and Restated Employment Agreement dated as of September 30, 2009 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/01/2009		
10.2.3	Amended and Restated Employment Agreement dated as of September 30, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009		
10.2.4	Amended and Restated Employment Agreement dated as of September 30, 2009 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/01/2009		
10.2.5	Amended and Restated Employment Agreement dated as of September 30, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009		
10.2.6	Employment Agreement dated as of November 5, 2010 between Domenic J. Dell Osso, Jr. and Chesapeake Energy Corporation.	10-Q	001-13726	10.2	11/09/2010		
10.2.7	Employment Agreement dated as of September 30, 2009 between Martha A. Burger and Chesapeake Energy Corporation.					X	
10.2.8	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.7	11/09/2009		

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		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.3	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
21	Subsidiaries of Chesapeake.					X	
23.1	Consent of PricewaterhouseCoopers, LLP.					X	
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
23.4	Consent of Lee Keeling and Associates, Inc.					X	
23.5	Consent of Ryder Scott Company, L.P.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	
99.2	Report of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
99.3	Report of Lee Keeling and Associates, Inc.					X	
99.4	Report of Ryder Scott Company, L.P.					X	
101.INS#	XBRL Instance Document.					X	X
101.SCH#	XBRL Taxonomy Extension Schema Document.					X	X
101.CAL#	XBRL Taxonomy Extension Calculation Linkbase Document.					X	X
101.DEF#	XBRL Taxonomy Extension Definition Linkbase Document.					X	X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
101.LAB#	XBRL Taxonomy Extension Labels Linkbase Document.					X	X
101.PRE#	XBRL Taxonomy Extension Presentation Linkbase Document.					X	X

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

Management contract or compensatory plan or arrangement.

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

Date: March 1, 2011

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

Chairman of the Board and Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Aubrey K. McClendon and Domenic J. Dell Osso, Jr., and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Annual Report on Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 1, 2011
/s/ DOMENIC J. DELL OSSO, JR. **Domenic J. Dell Osso, Jr.**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2011
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2011
/s/ RICHARD K. DAVIDSON **Richard K. Davidson**	Director	March 1, 2011
/s/ KATHLEEN EISBRENNER **Kathleen Eisbrenner**	Director	March 1, 2011
/s/ V. BURNS HARGIS **V. Burns Hargis**	Director	March 1, 2011

/s/ FRANK KEATING **Frank Keating**	Director	March 1, 2011
/s/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	March 1, 2011
/s/ MERRILL A. MILLER, JR. **Merrill A. Miller, Jr.**	Director	March 1, 2011
/s/ DON NICKLES **Don Nickles**	Director	March 1, 2011
/s/ FREDERICK B. WHITTEMORE **Frederick B. Whittemore**	Director	March 1, 2011

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INDEX TO EXHIBITS

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1*	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.5% Senior Notes due 2017.	8-K	001-13726	4.1	08/16/2005		
4.2*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2020.	8-K	001-13726	4.1.1	11/15/2005		
4.3*	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.75% Contingent Convertible Senior Notes due 2035.	8-K	001-13726	4.1.2	11/15/2005		
4.4*	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.625% Senior Notes due 2013.	8-K	001-13726	4.1	06/30/2006		
4.5*	Indenture dated as of December 6, 2006 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to 6.25% Senior Notes due 2017.	8-K	001-13726	4.1	12/06/2006		

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		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
4.6*	Indenture dated as of May 15, 2007 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.5% Contingent Convertible Senior Notes due 2037.	8-K	001-13726	4.1	05/15/2007		
4.7*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 7.25% Senior Notes due 2018.	8-K	001-13726	4.1	05/29/2008		
4.8*	Indenture dated as of May 27, 2008 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 2.25% Contingent Convertible Senior Notes due 2038.	8-K	001-13726	4.2	05/29/2008		
4.9*	Indenture dated as of February 2, 2009 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 9.5% Senior Notes due 2015.	8-K	001-13726	4.1	02/03/2009		
4.9.1*	First Supplemental Indenture dated as of February 10, 2009 to Indenture dated as of February 2, 2009, with respect to additional 9.5% Senior Notes due 2015.	8-K	001-13726	4.2	02/17/2009		
4.10*	Indenture dated as of August 2, 2010 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	333-168509	4.1	08/03/2010		
4.10.1*	First Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010, with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010		
4.10.2*	Second Supplemental Indenture dated as of August 17, 2010 to Indenture dated as of August 2, 2010 with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010		
4.10.3*	Fifth Supplemental Indenture, dated February 11, 2011 to Indenture dated as of August 2, 2010, with respect to 6.125% Senior Notes due 2021.	8-A	001-13726	4.2	2/22/2011		

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			Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
4.12*	Eighth Amended and Restated Credit Agreement, dated as of December 2, 2010, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration L.L.C., as Borrower, Union Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, The Royal Bank of Scotland plc and BNP Paribas, as Co-Syndication Agent, Credit Agricole Corporate and Investment Bank, as Documentation Agent, and the several lenders from time to time parties thereto.	8-K	001-13726	4.1	12/8/2010		
10.1.1	Chesapeake s 2003 Stock Incentive Plan, as amended.	10-Q	001-13726	10.1.1	11/09/2009		
10.1.2	Chesapeake s 1992 Nonstatutory Stock Option Plan, as amended.	10-Q	001-13726	10.1.2	02/14/1997		
10.1.3	Chesapeake s 1994 Stock Option Plan, as amended.	10-Q	001-13726	10.1.3	11/07/2006		
10.1.4	Chesapeake s 1996 Stock Option Plan, as amended.	10-Q	001-13726	10.1.4	11/07/2006		
10.1.5	Chesapeake s 1999 Stock Option Plan, as amended.	10-Q	001-13726	10.1.5	08/11/2008		
10.1.6	Chesapeake s 2000 Employee Stock Option Plan, as amended.	10-Q	001-13726	10.1.6	08/11/2008		
10.1.7	Chesapeake s 2001 Stock Option Plan, as amended.	10-Q	001-13726	10.1.8	08/11/2008		
10.1.8	Chesapeake s 2001 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.10	08/11/2008		
10.1.9	Chesapeake s 2002 Stock Option Plan, as amended.	10-Q	001-13726	10.1.11	08/11/2008		
10.1.10	Chesapeake s 2002 Non-Employee Director Stock Option Plan.	10-Q	001-13726	10.1.12	08/11/2008		
10.1.11	Chesapeake s 2002 Nonqualified Stock Option Plan, as amended.	10-Q	001-13726	10.1.13	08/11/2008		
10.1.12	Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, as amended.	10-K	001-13726	10.1.14	02/29/2008		
10.1.13	Chesapeake Energy Corporation Amended and Restated Deferred Compensation Plan.					X	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	06/17/2010		
10.1.14.1	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.					X	
10.1.14.2	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan.	8-K	001-13726	10.1.18.3	06/16/2005		

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.1.15	Founder Well Participation Program.	DEF -14A	001-13726	B	04/29/2005		
10.2.1	Third Amended and Restated Employment Agreement dated as of March 1, 2009 between Aubrey K. McClendon and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.1	05/11/2009		
10.2.2	Amended and Restated Employment Agreement dated as of September 30, 2009 between Marcus C. Rowland and Chesapeake Energy Corporation.	8-K	001-13726	10.2.2	10/01/2009		
10.2.3	Amended and Restated Employment Agreement dated as of September 30, 2009 between Steven C. Dixon and Chesapeake Energy Corporation.	8-K	001-13726	10.2.3	10/01/2009		
10.2.4	Amended and Restated Employment Agreement dated as of September 30, 2009 between J. Mark Lester and Chesapeake Energy Corporation.	8-K	001-13726	10.2.4	10/01/2009		
10.2.5	Amended and Restated Employment Agreement dated as of September 30, 2009 between Douglas J. Jacobson and Chesapeake Energy Corporation.	8-K	001-13726	10.2.5	10/01/2009		
10.2.6	Employment Agreement dated as of November 5, 2010 between Domenic J. Dell Osso, Jr. and Chesapeake Energy Corporation.	10-Q	001-13726	10.2	11/09/2010		
10.2.7	Employment Agreement dated as of September 30, 2009 between Martha A. Burger and Chesapeake Energy Corporation.					X	
10.2.8	Form of Employment Agreement between Senior Vice President and Chesapeake Energy Corporation.	10-Q	001-13726	10.2.7	11/09/2009		
10.3	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries.	10-K	001-13726	10.3	02/29/2008		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X	
21	Subsidiaries of Chesapeake.					X	
23.1	Consent of PricewaterhouseCoopers, LLP.					X	
23.2	Consent of Netherland, Sewell & Associates, Inc.					X	
23.3	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
23.4	Consent of Lee Keeling and Associates, Inc.					X	

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
23.5	Consent of Ryder Scott Company, L.P.					X	
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
31.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X	
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
32.2	Domenic J. Dell Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.						X
99.1	Report of Netherland, Sewell & Associates, Inc.					X	
99.2	Report of Data & Consulting Services, Division of Schlumberger Technology Corporation.					X	
99.3	Report of Lee Keeling and Associates, Inc.					X	
99.4	Report of Ryder Scott Company, L.P.					X	
101.INS#	XBRL Instance Document.					X	X
101.SCH#	XBRL Taxonomy Extension Schema Document.					X	X
101.CAL#	XBRL Taxonomy Extension Calculation Linkbase Document.					X	X
101.DEF#	XBRL Taxonomy Extension Definition Linkbase Document.					X	X
101.LAB#	XBRL Taxonomy Extension Labels Linkbase Document.					X	X
101.PRE#	XBRL Taxonomy Extension Presentation Linkbase Document.					X	X

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

Management contract or compensatory plan or arrangement.