NEWS RELEASE

CHESAPEAKE ENERGY

Chesapeake Energy Corporation Reports Financial Results for the 2010 First Quarter

Company Reports 2010 First Quarter Net Income to Common Stockholders of $590 Million, or $0.92 per Fully Diluted Common Share, on Revenue of $2.8 Billion; Adjusted Net Income Available to Common Stockholders Was $524 Million, or $0.82 per Fully Diluted Common Share; Adjusted Ebitda of $1.3 Billion and Operating Cash Flow of $1.2 Billion Achieved Company Reports 2010 First Quarter Production of 2.586 Bcfe per Day, an Increase of 9% over 2009 First Quarter Production; Production Increases 19% Year-Over-Year Adjusted for Asset Sales; Production of Oil and Natural Gas Liquids Increases 35% Year-Over-Year Company Redirects Capital and Planned Operated Drilling Activity from Natural Gas Plays to Oil and Natural Gas Liquids Plays

OKLAHOMA CITY, May 04, 2010 (BUSINESS WIRE) --Chesapeake Energy Corporation (NYSE:CHK) today announced financial results for the 2010 first quarter. For the 2010 first quarter, Chesapeake reported net income to common stockholders of $590 million ($0.92 per fully diluted common share), operating cash flow of $1.166 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.441 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization) on revenue of $2.798 billion and production of 233 billion cubic feet of natural gas equivalent (bcfe).

The company's 2010 first quarter results include a realized natural gas and oil hedging gain of $399 million. The results also include various items that are typically not included in published estimates of the company's financial results by certain securities analysts. Excluding the items detailed below, for the 2010 first quarter, Chesapeake reported adjusted net income to common stockholders of $524 million ($0.82 per fully diluted common share) and adjusted ebitda of $1.270 billion. The excluded items and their effects on 2010 first quarter reported results are detailed as follows:

- - a net non-cash unrealized after-tax mark-to-market gain of $209 million resulting from the company's natural gas, oil and interest rate hedging programs;
- - a non-cash after-tax charge of $142 million related to the deconsolidation of the company's midstream joint venture; and
- - a non-cash after-tax charge of $1 million on exchanges of certain of the company's contingent convertible senior notes for shares of common stock.

The various items described above do not materially affect the calculation of operating cash flow. A reconciliation of operating cash flow, ebitda, adjusted ebitda and adjusted net income to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 11 - 13 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2010 first quarter and compares them to results during the 2009 fourth quarter and the 2009 first quarter.

	Three Months Ended		
	3/31/10	**12/31/09**	**3/31/09**
Average daily production (in mmcfe) [(a)]	2,586	2,618	2,367
Natural gas as % of total production	90	93	92
Natural gas production (in bcf)	209.6	224.5	195.7
Average realized natural gas price ($/mcf) [(b)]	6.31	6.05	6.05
Oil and natural gas liquids production (in mbbls)	3,871	2,737	2,874
Average realized oil and natural gas liquids price ($/bbl) [(b)]	67.70	71.61	39.12
Natural gas equivalent production (in bcfe)	232.8	240.9	213.0
Natural gas equivalent realized price ($/mcfe) [(b)]	6.80	6.45	6.09
Marketing, gathering and compression net margin($/mcfe)	.12	.23	.14
Service operations income ($/mcfe)	.03	.02	.03
Production expenses ($/mcfe)	(.89)	(.86)	(1.12)
Production taxes ($/mcfe)	(.21)	(.15)	(.11)
General and administrative costs ($/mcfe) [(c)]	(.38)	(.28)	(.33)
Stock-based compensation ($/mcfe)	(.09)	(.09)	(.09)
DD&A of natural gas and oil properties ($/mcfe)	(1.32)	(1.39)	(2.10)
D&A of other assets ($/mcfe)	(.21)	(.28)	(.27)
Interest expense ($/mcfe) [(b)]	(.22)	(.19)	(.14)
Operating cash flow ($ in millions) [(d)]	1,166	1,212	999
Operating cash flow ($/mcfe)	5.01	5.03	4.69
Adjusted ebitda ($ in millions) [(e)]	1,270	1,256	988
Adjusted ebitda ($/mcfe)	5.46	5.21	4.64
Net income (loss) to common stockholders ($ in millions)	590	(530)	(5,746)
Earnings (loss) per share - assuming dilution ($)	.92	(.84)	(9.63)
Adjusted net income to common stockholders ($ in millions) [(f)]	524	490	277
Adjusted earnings per share - assuming dilution ($)	.82	.77	.46

(a) 2010 production reflects the sale of a 25% joint venture interest in the company's Barnett Shale assets on

January 25, 2010 (averaging approximately 155 mmcfe per day during the 2010 first quarter) and its sixth

volumetric production payment transaction on February 5, 2010 (averaging approximately 14 mmcfe per day

during the 2010 first quarter)

(b) Includes the effects of realized gains (losses) from hedging, but does not include the effects of unrealized

gains (losses) from hedging

(c) Excludes expenses associated with non-cash stock-based compensation

(d) Defined as cash flow provided by operating activities before changes in assets and liabilities

(e) Defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and

amortization expense, as adjusted to remove the effects of certain items detailed on page 12

(f) Defined as net income (loss) available to common stockholders, as adjusted to remove the effects of certain

items detailed on page 13.

2010 First Quarter Average Daily Production Increases 9% over 2009 First Quarter Production; Production Increases 19% Year-Over-Year Adjusted for Asset Sales; Oil and Natural Gas Liquids Production Increases 35% Year-Over-Year

As announced on May 3, 2010, Chesapeake's daily production for the 2010 first quarter averaged 2.586 bcfe, a decrease of 32 million cubic feet of natural gas equivalent (mmcfe), or 1%, below the 2.618 bcfe produced per day in the 2009 fourth quarter and an increase of 219 mmcfe, or 9%, over the 2.367 bcfe produced per day in the 2009 first quarter. Adjusted for 2010 first quarter asset sales of a 25% joint venture interest in the company's Barnett Shale assets (averaging approximately 155 mmcfe per day of production during the 2010 first quarter) and the company's sixth volumetric production payment transaction (averaging approximately 14 mmcfe per day during the 2010 first quarter), Chesapeake's sequential and year-over-year daily production growth rates would have been 5% and 19%, respectively.

Chesapeake's average daily production of 2.586 bcfe for the 2010 first quarter consisted of 2.328 billion cubic feet of natural gas (bcf) and 43,011 barrels of oil and natural gas liquids (bbls). The company's 2010 first quarter production of 232.8 bcfe was comprised of 209.6 bcf (90% on a natural gas equivalent basis) and 3.9 million barrels of oil and natural gas liquids (mmbbls) (10% on a natural gas equivalent basis). The company's year-over-year growth rate of natural gas production was 7% and its year-over-year growth rate of oil and natural gas liquids production was 35%.

Chesapeake anticipates reporting full-year production growth of approximately 8-10% in 2010 and 16-18% in 2011 and expects to increase its oil and natural gas liquids production to more than 100,000 bbls per day, or 15-20% of total production, by year-end 2012 through organic growth.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2010 first quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $6.31 per thousand cubic feet (mcf) and $67.70 per bbl, for a realized natural gas equivalent price of $6.80 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas and oil hedging activities during the 2010 first quarter generated a $1.81 gain per mcf and a $5.11 gain per bbl for a 2010 first quarter realized hedging gain of $399 million, or $1.71 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2010 first quarter were a negative $0.80 per mcf and a negative $16.12 per bbl.

By comparison, average prices realized during the 2009 first quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $6.05 per mcf and $39.12 per bbl, for a realized natural gas equivalent price of $6.09 per mcfe. Realized gains from natural gas and oil hedging activities during the 2009 first quarter generated a $2.61 gain per mcf and a $3.13 gain per bbl for a 2009 first quarter realized hedging gain of $519 million, or $2.44 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2009 first quarter were a negative $1.47 per mcf and a negative $7.09 per bbl.

The following tables summarize Chesapeake's 2010 and 2011 open hedge positions through swaps and collars as of May 4, 2010. Depending on changes in natural gas and oil futures markets and management's view of underlying natural gas and oil supply and demand trends, Chesapeake may either increase or decrease its hedging positions at any time in the future without notice.

Open Swap Positions as of May 4, 2010

Year	Natural Gas % Hedged	Natural Gas $ NYMEX	Oil % Hedged	Oil $ NYMEX
2010	55 %	7.52	52 %	89.62
2011	16 %	7.91	12 %	96.09

Open Natural Gas Collar Positions as of May 4, 2010

Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2010	4 %	7.21	9.97
2011	1 %	7.70	11.50

As of April 30, 2010, Chesapeake's natural gas and oil hedging positions with its 14 different counterparties had a positive mark-to-market value of approximately $265 million. The company's natural gas and oil realized hedging gains for the first three months of 2010 were $399 million and since January 1, 2001 have been $4.8 billion.

The company's updated forecasts and hedging positions for 2010 and 2011 are attached to this release in an Outlook dated May 4, 2010, labeled as Schedule "A," which begins on page 14. This Outlook has been changed from the Outlook dated February 17, 2010, attached as Schedule "B," which begins on page 18, to reflect various updated information.

Company Redirects Capital and Planned Operated Drilling Activity from Natural Gas Plays to Oil and Natural Gas Liquids Plays

Due to recent low natural gas prices and ongoing success in the company's liquids-rich plays, Chesapeake has revised its 2010 and 2011 drilling plans to redirect capital from its natural gas plays to its liquids-rich plays. In its natural gas shale plays, Chesapeake has reduced its previously planned 2010 peak of 120 operated rigs to approximately 106 rigs and its planned 2011 peak of 122 operated rigs to approximately 105 rigs. In total, the company has reduced its planned capital expenditures on natural gas-focused plays by approximately $300 million and $400 million in 2010 and 2011, 12% and 17%, respectively. The company plans to redirect this capital to accelerate drilling activity in its increasingly successful liquids-rich plays. In particular, Chesapeake plans to increase its drilling activity in its Granite Wash, Eagle Ford Shale, Anadarko Basin, Permian Basin and Rocky Mountain unconventional liquids-rich plays where it is currently drilling with 21 operated drilling rigs. Chesapeake has acquired approximately 1.9 million net acres of leasehold in these plays, and its goal is to achieve a 50-operated-rig drilling program in these plays within the next six to 12 months, which would lead to more rapid value creation from the company's liquids-rich assets. Chesapeake is exploring various alternatives to enable it to recover its leasehold expenditures and to fund accelerated drilling in these plays.

Company Provides Update on Recently Completed and Pending Asset Monetizations

In January 2010, Chesapeake completed its Barnett Shale joint venture with Total E&P USA, Inc., a wholly owned subsidiary of Total S.A. (NYSE:TOT; FP:FP), in which Total paid $800 million in cash at closing and agreed to pay $1.45 billion in drilling carries, of which approximately $450 million is expected to be received in 2010. In February 2010, the company completed its sixth volumetric production payment (VPP) for proceeds of $180 million, or $3.95 per mcfe of proved reserves. In March 2010, as part of its joint venture arrangement with Statoil (NYSE:STO; OSE:STL), Chesapeake sold approximately 50,000 net acres of leasehold in the Marcellus Shale for approximately $245 million to Statoil.

Subsequent to the end of the 2010 first quarter, Chesapeake sold or has agreed to sell leasehold and producing assets for combined proceeds of approximately $750 million in three asset sale transactions and a VPP. The asset sale transactions include $400 million of non-core producing assets in the Permian Basin and the Appalachian Basin with combined production of approximately 30 mmcfe per day and proved reserves of approximately 180 bcfe as well as certain non-core East Texas Haynesville Shale leasehold. In addition, Chesapeake anticipates completing its seventh VPP transaction in May 2010 on certain Chesapeake-operated long-lived oil and liquids-rich producing assets in the Permian Basin for proceeds of approximately $350 million, or approximately $8.75 per mcfe of proved reserves. The assets in the pending seventh VPP include proved reserves of approximately 40 bcfe and current net production of approximately 6 mmcf and 2,200 bbls per day.

Conference Call Information

A conference call to discuss this release of financial results and the company's release of its operational results issued on May 3, 2010 has been scheduled for Wednesday morning, May 5, 2010, at 10:00 a.m. EDT. The telephone number to access the conference call is **913-312-0677** or toll-free **888-812-8589**. The passcode for the call is **4406803**. We encourage those who would like to participate in the call to dial the access number between 9:50 and 10:00 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from 2:00 p.m. EDT on May 5, 2010 through midnight EDT on May 19, 2010. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **4406803**. The conference call will also be webcast live on the Internet and can be accessed by going to Chesapeake's website at www.chk.com in the "Events" subsection of the "Investors" section of the website. The webcast of the conference call will be available on Chesapeake's website for one year.

This press release and the accompanying Outlooks include "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 give our current expectations or forecasts of future events. They include expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned drilling activity, drilling and completion costs and anticipated asset sales, projected cash flow and liquidity, business strategy and other plans and objectives for future operations Disclosures concerning the fair value 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. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this press release, and we undertake no *obligation to update this information.*

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in our 2009 Form 10-K filed with the U.S. Securities and Exchange Commission on March 1, 2010. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures; potential differences in our interpretations of new reserve disclosure rules and future SEC guidance; inability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities; a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes 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 adverse results in pending or future litigation.

Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. 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.

Chesapeake Energy Corporation is the second-largest producer of natural gas and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Fayetteville, Haynesville, Marcellus, and Bossier natural gas shale plays and in the Eagle Ford, Granite Wash and various other unconventional oil plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. Further information is available at www.chk.com.

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

($ in millions, except per-share and unit data)

(unaudited)

THREE MONTHS ENDED:	**March 31, 2010**		**March 31, 2009**	
	$	**$/mcfe**	**$**	**$/mcfe**
REVENUES:				
Natural gas and oil sales	1,898	8.16	1,397	6.56
Marketing, gathering and compression sales	844	3.62	552	2.59

Service operations revenue	56	0.24	46	0.22
Total Revenues	2,798	12.02	1,995	9.37
OPERATING COSTS:				
Production expenses	207	0.89	238	1.12
Production taxes	48	0.21	23	0.11
General and administrative expenses	109	0.47	90	0.42
Marketing, gathering and compression expenses	815	3.50	523	2.45
Service operations expense	49	0.21	40	0.19
Natural gas and oil depreciation, depletion and amortization	308	1.32	447	2.10
Depreciation and amortization of other assets	50	0.21	57	0.27
Impairment of natural gas and oil properties and other assets	--	--	9,630	45.21
Total Operating Costs	1,586	6.81	11,048	51.87
INCOME (LOSS) FROM OPERATIONS	1,212	5.21	(9,053)	(42.50)
OTHER INCOME (EXPENSE):				
Other income (expense)	15	0.07	8	0.04
Interest expense	(25)	(0.11)	14	0.06
Impairment of investments	--	--	(153)	(0.72)
Gain (loss) on exchanges of Chesapeake debt	(2)	(0.01)	--	--
Total Other Income (Expense)	(12)	(0.05)	(131)	(0.62)
INCOME (LOSS) BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	1,200	5.16	(9,184)	(43.12)
Income Tax Expense (Benefit):				
Current income taxes	--	--	--	--
Deferred income taxes	462	1.99	(3,444)	(16.17)
Total Income Tax Expense (Benefit)	462	1.99	(3,444)	(16.17)
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	738	3.17	(5,740)	(26.95)
Cumulative effect of accounting change, net of tax	(142)	(0.61)	--	--
NET INCOME (LOSS)	596	2.56	(5,740)	(26.95)
Preferred stock dividends	(6)	(0.02)	(6)	(0.03)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	590	2.54	(5,746)	(26.98)
EARNINGS (LOSS) PER COMMON SHARE - BASIC:				
Income before cumulative effect of accounting change	$ 1.17		$ (9.63)	
Cumulative effect of accounting change	(0.23)		--	
	$ 0.94		$ (9.63)	
EARNINGS (LOSS) PER COMMON SHARE - ASSUMING DILUTION:				
Income before cumulative effect of accounting change	$ 1.14		$ (9.63)	
Cumulative effect of accounting change	(0.22)		--	
	$ 0.92		$ (9.63)	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				

Basic	630	597
Assuming dilution	647	597

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

($ in millions)

(unaudited)

	March 31, 2010	December 31, 2009
Cash and cash equivalents	$ 516	$ 307
Other current assets	2,819	2,139
Total Current Assets	3,335	2,446
Property and equipment (net)	25,655	26,710
Other assets	1,298	758
Total Assets	$ 30,288	$ 29,914
Current liabilities	$ 3,123	$ 2,688
Long-term debt, net [(a)]	12,204	12,295
Asset retirement obligation	283	282
Other long-term liabilities	1,167	1,249
Deferred tax liability	1,295	1,059
Total Liabilities	18,072	17,573
Chesapeake Stockholders' Equity	12,216	11,444
Noncontrolling interest	--	897
Total equity	12,216	12,341
Total Liabilities & Equity	$ 30,288	$ 29,914
Common Shares Outstanding (in millions)	651	648

CHESAPEAKE ENERGY CORPORATION

CAPITALIZATION

($ in millions)

(unaudited)

	March 31, 2010	% of Total Book Capitalization		December 31, 2009[(a)]	% of Total Book Capitalization	
Total debt, net of cash [(a)]	$ 11,688	49	%	$ 11,988	49	%
Chesapeake stockholders' equity	12,216	51	%	11,444	47	%
Noncontrolling interest [(b)]	--	--		897	4	%

Total	$ 23,904	100	%	$ 24,329	100	%

(a) At March 31, 2010, includes $1.872 billion of combined borrowings under the company's $3.5 billion revolving bank credit facility and the company's $250 million midstream revolving bank credit facility. At March 31, 2010, the company had $1.837 billion of additional borrowing capacity under these two revolving bank credit facilities.

(b) Effective January 1, 2010, we no longer consolidate the company's midstream joint venture and consequently no longer report a noncontrolling interest related to this investment.

CHESAPEAKE ENERGY CORPORATION

SUPPLEMENTAL DATA - NATURAL GAS AND OIL SALES AND INTEREST EXPENSE

(unaudited)

THREE MONTHS ENDED:	March 31, 2010	March 31, 2009
Natural Gas and Oil Sales ($ in millions):		
Natural gas sales	$ 942	$ 674
Natural gas derivatives - realized gains (losses)	379	510
Natural gas derivatives - unrealized gains (losses)	415	68
Total Natural Gas Sales	1,736	1,252
Oil sales	242	104
Oil derivatives - realized gains (losses)	20	9
Oil derivatives - unrealized gains (losses)	(100)	32
Total Oil Sales	162	145
Total Natural Gas and Oil Sales	$ 1,898	$ 1,397
Average Sales Price - excluding gains (losses) on derivatives:		
Natural gas ($ per mcf)	$ 4.50	$ 3.44
Oil ($ per bbl)	$ 62.59	$ 35.99
Natural gas equivalent ($ per mcfe)	$ 5.09	$ 3.65
Average Sales Price - excluding unrealized gains (losses) on derivatives:		
Natural gas ($ per mcf)	$ 6.31	$ 6.05
Oil ($ per bbl)	$ 67.70	$ 39.12
Natural gas equivalent ($ per mcfe)	$ 6.80	$ 6.09
Interest Expense (Income) ($ in millions):		
Interest	$ 55	$ 38
Derivatives - realized (gains) losses	(3)	(7)
Derivatives - unrealized (gains) losses	(27)	(45)
Total Interest Expense	$ 25	$ (14)

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	March 31, 2010	March 31, 2009
Beginning cash	$ 307	$ 1,749
Cash provided by operating activities	$ 1,183	$ 1,261
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	$ (1,014)	$ (1,347)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(968)	(413)
Proceeds from divestitures of proved and unproved properties, leasehold and VPPs	1,156	--
Additions to other property and equipment	(279)	(667)
Additions to investments	(6)	(8)
Proceeds from sale of compressors	--	68
Proceeds from sale of other assets	56	--
Deposits for divestitures	21	--
Other	20	--
Total cash (used in) investing activities	$ (1,014)	$ (2,367)
Cash provided by (used in) financing activities	$ 40	$ (560)
Ending cash	$ 516	$ 83

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	March 31, 2010	December 31, 2009	March 31, 2009
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,183	$ 1,226	$ 1,261
Changes in assets and liabilities	(17)	(14)	(262)
OPERATING CASH FLOW [(a)]	$ 1,166	$ 1,212	$ 999

THREE MONTHS ENDED:	March 31, 2010	December 31, 2009	March 31, 2009
NET INCOME (LOSS)	$ 596	$ (499)	$ (5,740)
Income tax expense (benefit)	462	(299)	(3,444)
Interest expense (income)	25	62	(14)
Depreciation and amortization of other assets	50	67	57
Natural gas and oil depreciation, depletion and amortization	308	335	447

EBITDA (b)	$ 1,441	$ (334)	$ (8,694)

THREE MONTHS ENDED:	**March 31, 2010**	**December 31, 2009**	**March 31, 2009**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,183	$ 1,226	$ 1,261
Changes in assets and liabilities	(17)	(14)	(262)
Interest expense (income)	25	62	(14)
Unrealized gains (losses) on natural gas and oil derivatives	315	(186)	101
Cumulative effect of accounting change, net of tax	(142)	--	--
Impairment of natural gas and oil properties and other assets	--	(1,408)	(9,630)
Impairment of investments	--	--	(153)
Other non-cash items	77	(14)	3
EBITDA (b)	$ 1,441	$ (334)	$ (8,694)

(a) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of a natural gas and oil company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the natural gas and oil exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

(b) Ebitda represents net income (loss) before income tax expense, interest expense and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements and our senior note indentures. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	**March 31, 2010**	**December 31, 2009**	**March 31, 2009**
EBITDA	$ 1,441	$ (334)	$ (8,694)
Adjustments:			
(Income) attributable to noncontrolling	--	(25)	--

interest			
Cumulative effect of accounting change, net of tax	142	--	--
Unrealized (gains) losses on natural gas and oil derivatives	(315)	186	(101)
Loss (gain) on exchanges of Chesapeake debt	2	21	--
Impairment of natural gas and oil properties and other Assets	--	1,408	9,630
Impairment of investments	--	--	153
Adjusted EBITDA (a)	$ 1,270	$ 1,256	$ 988

(a) Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to ebitda because:

i. Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.

ii. Adjusted ebitda is more comparable to estimates provided by securities analysts.

iii. Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

($ in millions, except per-share data)

(unaudited)

THREE MONTHS ENDED:	March 31, 2010	December 31, 2009	March 31, 2009
Net income (loss) available to Chesapeake common stockholders	$ 590	(530)	$ (5,746)
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	(209)	126	(91)
Impairment of natural gas and oil properties and other assets, net of tax	--	880	6,019
Cumulative effect of accounting change, net of tax	142	--	--
Impairment of investments, net of tax	--	--	95
Loss (gain) on exchanges of Chesapeake debt, net of tax	1	14	--
Adjusted net income available to Chesapeake common stockholders (a)	524	490	277
Preferred stock dividends	6	6	6

Total adjusted net income	$ 530	$ 496	$ 283
Weighted average fully diluted shares outstanding [b]	647	644	613
Adjusted earnings per share assuming dilution[a]	$ 0.82	$ 0.77	$ 0.46

(a) Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to GAAP earnings because:

i. Management uses adjusted net income available to common stockholders to evaluate the company's

operational trends and performance relative to other natural gas and oil producing companies.

ii. Adjusted net income available to common stockholders is more comparable to earnings estimates

provided by securities analysts.

iii. Items excluded generally are one-time items or items whose timing or amount cannot be reasonably

estimated. Accordingly, any guidance provided by the company generally excludes information

regarding these types of items.

(b) Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF MAY 4, 2010

Years Ending December 31, 2010 and 2011

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of May 4, 2010, we are using the following key assumptions in our projections for 2010 and 2011.

The primary changes from our February 17, 2010 Outlook are in ***italicized bold*** and are explained as follows:

1. Our production guidance has been increased;
2. Projected effects of changes in our hedging positions have been updated;
3. Equivalent shares outstanding has been updated to reflect exchanges of convertible senior notes; and
4. Our cash flow projections have been updated, including increased drilling capital expenditures to reflect additional drilling on oil and natural gas liquids rich plays and anticipated cost inflation, partially offset by improved drilling efficiencies.

	Year Ending 12/31/2010	**Year Ending 12/31/2011**
Estimated Production:		
Natural gas - bcf	***874 - 894***	***990 - 1,010***
Oil - mbbls	***17,000***	***26,500***
Natural gas equivalent - bcfe	***976 - 996***	***1,149 - 1,169***

Daily natural gas equivalent midpoint - mmcfe	2,700	***3,175***
Year-over-year (YOY) estimated production increase	8 - 10%	***16 - 18%***
YOY estimated production increase excluding asset sales	15 - 17%	***17 - 19%***
NYMEX Price[a] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$5.21***	***$6.50***
Oil - $/bbl	***$79.68***	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	***$1.82***	***$0.33***
Oil - $/bbl	***$4.05***	***$3.82***
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	***15 - 20%***	***15 - 20%***
Oil - $/bbl	***15 - 20%***	***15 - 20%***
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.85 - 0.95	$0.85 - 0.95
Production taxes (~ 5% of O&G revenues)	$0.25 - 0.30	$0.30 - 0.35
General and administrative[b]	$0.30 - 0.35	$0.30 - 0.35
Stock-based compensation (non-cash)	$0.09 - 0.11	$0.09 - 0.11
DD&A of natural gas and oil assets	$1.35 - 1.55	$1.35 - 1.55
Depreciation of other assets	$0.20 - 0.25	$0.20 - 0.25
Interest expense[c]	$0.30 - 0.35	$0.30 - 0.35
Other Income per Mcfe:		
Marketing, gathering and compression net margin	$0.07 - 0.09	$0.07 - 0.09
Service operations net margin	$0.04 - 0.06	$0.04 - 0.06
Equity in income of midstream joint venture (CMP)	$0.04 - 0.06	$0.04 - 0.06
Book Tax Rate (all deferred)	38.5%	38.5%
Equivalent Shares Outstanding (in millions):		
Basic	***630 - 635***	***640 - 645***
Diluted	***645 - 650***	***650 - 655***
Operating cash flow before changes in assets and liabilities[d][e]	***$4,800 - 4,900***	***$5,100 - 5,800***
Drilling and completion costs[f]	***($4,200 - 4,500)***	($4,300 - 4,600)
Dividends, capitalized interest, cash income taxes, etc.	($350 - 400)	($500 - 600)

Note: refer to footnotes on following page

(a) NYMEX natural gas prices have been updated for actual contract prices through May 2010 and NYMEX oil prices have been updated for actual contract prices through March 2010.

(b) Excludes expenses associated with noncash stock compensation.

(c) Does not include gains or losses on interest rate derivatives.

(d) A non-GAAP financial measure. We are unable to provide a reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities.

(e) Assumes NYMEX prices of $5.00 to $6.00 per mcf and $80.00 per bbl in 2010 and $6.00 to $7.00 per mcf and $80.00 per bbl in 2011.

(f) Net of drilling carries.

At March 31, 2010, the company had approximately $2.4 billion of cash and cash equivalents and additional borrowing capacity under its two revolving bank credit facilities.

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future natural gas and oil production. These strategies include:

1) Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
2) 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.
3) 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.
4) Call options: Chesapeake sells call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.
5) 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.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into natural gas and oil derivative transactions in order to mitigate a portion of its exposure to adverse market changes in natural gas and oil prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to natural gas and oil sales. All realized gains and losses from natural gas and oil derivatives are included in natural gas and oil sales in the month of related production. In accordance with generally accepted accounting principles, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these nonqualifying derivatives that occur prior to their maturity (i.e., because of temporary fluctuations in value) are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in natural gas and oil sales.

The company currently has the following open natural gas swaps in place for 2010 and 2011 and also has the following gains from lifted natural gas trades:

	Open Swaps (Bcf)	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production (Bcf)	Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Gains from Lifted Trades ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q2 2010	***129***	***$ 7.40***			***$ 36.9***	
Q3 2010	***119***	***$ 7.46***			***$ 64.8***	
Q4 2010	***120***	***$ 7.70***			***$ 64.4***	
Q2-Q4 2010[(a)]	***368***	***$ 7.52***	***675***	***55 %***	***$ 166.1***	***$ 0.25***
Total 2011[(a)]	***157***	***$ 7.91***	***1,000***	***16 %***	***$ 59.6***	$ 0.06

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at prices ranging from $6.50 to $6.75 covering 5 bcf in Q2-Q4 2010 and $5.75 to $6.50 covering 24 bcf in 2011.

The company currently has the following open natural gas collars in place for 2010 and 2011:

	Open Collars (Bcf)	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production (Bcf)	Open Collars as a % of Estimated Total Natural Gas Production
Q2 2010	16	$ 7.04	$ 9.17		
Q3 2010	4	$ 7.60	$ 11.75		
Q4 2010	4	$ 7.60	$ 11.75		
Q2-Q4 2010[(a)]	***24***	***$ 7.21***	***$ 9.97***	***675***	***4 %***

Total 2011	7	$ 7.70	$ 11.50	***1,000***	***1***	***%***

(a) Certain collar arrangements include three-way collars that include written put options with a strike price of $4.35 covering 4 bcf in 2010.

The company currently has the following natural gas written call options in place for 2010 and 2011:

	Call Options (Bcf)	**Avg. NYMEX Floor Price**	**Avg. Premium per mcf**	**Assuming Natural Gas Production (Bcf)**	**Call Options as a % of Estimated Total Natural Gas Production**	
Q2 2010	***28***	***$ 9.94***	***$ 1.46***			
Q3 2010	***39***	***$ 9.89***	***$ 1.10***			
Q4 2010	***39***	***$ 10.07***	***$ 1.10***			
Q2-Q4 2010	***106***	***$ 9.97***	***$ 1.20***	***675***	***16***	***%***
Total 2011	***69***	***$ 9.51***	***$ 0.61***	***1,000***	7	%

The company has the following natural gas basis protection swaps in place for 2010, 2011 and 2012:

	Non-Appalachia Volume (Bcf)	NYMEX less[a]	Appalachia Volume (Bcf)	NYMEX plus[a]
Q2-Q4 2010	--	$ --	***8***	$ 0.26
2011	45	0.82	12	0.25
2012	43	0.85	--	--
Totals	88	$ 0.84	***20***	$ 0.26

(a) weighted average

The company also has the following crude oil swaps in place for 2010 and 2011:

	Open Swaps (mbbls)	**Avg. NYMEX Strike Price**	**Assuming Oil Production (mbbls)**	**Open Swap Positions as a % of Estimated Total Oil Production**		**Total Gains (Losses) from Lifted Trades ($ millions)**	**Total Lifted Gains (Losses) per bbl of Estimated Total Oil Production**
Q2 2010	2,275	$ 89.62	***--***	***--***		$ (4.0)	--
Q3 2010	2,300	$ 89.62	***--***	***--***		***$ (4.1)***	***--***
Q4 2010	2,300	$ 89.62	***--***	***--***		***$ (4.1)***	***--***
Q2-Q4 2010[a]	6,875	$ 89.62	***13,100***	***52***	***%***	***$ (12.2)***	***$ (0.93)***

Total 2011[a]	3,285	$ 96.09	***26,500***	***12 %***	***$ 32.9***	***$ 1.24***

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices of $60.00 covering 4 mmbbls and 1 mmbbls in Q2-Q4 2010 and 2011, respectively.

Note: Not shown above are written call options covering 1 mmbbls of oil production in Q2-Q4 2010 at a weighted average price of $101.25 per bbl for a weighted average discount of $1.93 per bbl and 3 mmbls of oil production in 2011 at a weighted average price of $93.13 per bbl for a weighted average premium of $5.34 per bbl.

SCHEDULE "B"

CHESAPEAKE'S OUTLOOK AS OF FEBRUARY 17, 2010 (PROVIDED FOR REFERENCE ONLY) NOW SUPERSEDED BY OUTLOOK AS OF MAY 4, 2010

Years Ending December 31, 2010 and 2011

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of February 17, 2010, we are using the following key assumptions in our projections for 2010 and 2011.

The primary changes from our January 4, 2010 Outlook are in ***italicized bold*** and are explained as follows:

1. Our production guidance has been increased;
2. Projected effects of changes in our hedging positions have been updated;
3. Certain cost assumptions have been updated;
4. Our rate of DD&A for natural gas and oil has been reduced to reflect our 2009 year-end impairment charge; and
5. Our cash flow projections have been updated, including increased drilling capital expenditures to reflect additional drilling on oil and natural gas liquids rich plays and anticipated cost inflation, partially offset by improved drilling efficiencies.

	Year Ending 12/31/2010	Year Ending 12/31/2011
Estimated Production:		
Natural gas - bcf	882 - 902	***1,025 - 1,045***
Oil - mbbls	***15,500***	***17,500***
Natural gas equivalent - bcfe	***975 - 995***	***1,130 - 1,150***
Daily natural gas equivalent midpoint - mmcfe	***2,700***	***3,125***
Year-over-year estimated production increase	***8 - 10%***	***15 - 17%***
Year-over-year estimated production increase excluding divestitures and curtailments	***15 - 17%***	***16 - 18%***
NYMEX Price[a] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$6.26***	$7.50
Oil - $/bbl	***$79.87***	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		

Natural gas - $/mcf	***$1.24***	***$0.25***
Oil - $/bbl	***$4.25***	***$5.78***
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	15 - 25%	15 - 25%
Oil - $/bbl	***10 - 15%***	***10 - 15%***
Operating Costs per Mcfe of Projected Production:		
Production expense	***$0.85 - 0.95***	***$0.85 - 0.95***
Production taxes (~ 5% of O&G revenues)	***$0.25 - 0.30***	$0.30 - 0.35
General and administrative(b)	***$0.30 - 0.35***	***$0.30 - 0.35***
Stock-based compensation (non-cash)	***$0.09 - 0.11***	***$0.09 - 0.11***
DD&A of natural gas and oil assets	***$1.35 - 1.55***	***$1.35 - 1.55***
Depreciation of other assets	$0.20 - 0.25	$0.20 - 0.25
Interest expense(c)	***$0.30 - 0.35***	***$0.30 - 0.35***
Other Income per Mcfe:		
Marketing, gathering and compression net margin	$0.07 - 0.09	$0.07 - 0.09
Service operations net margin	$0.04 - 0.06	$0.04 - 0.06
Equity in income of midstream joint venture (CMP)	$0.04 - 0.06	$0.04 - 0.06
Book Tax Rate (all deferred)	***38.5%***	***38.5%***
Equivalent Shares Outstanding (in millions):		
Basic	625 - 630	635 - 640
Diluted	640 - 645	645 - 650

	Year Ending 12/31/2010	**Year Ending 12/31/2011**
Cash Flow Projections ($ in millions):		
Operating cash flow before changes in assets and liabilities(d)(e)	***$4,900 - 5,000***	***$5,300 - 6,000***
Net leasehold and producing property transactions	$1,300 - 1,700	$1,000 - 1,300
Drilling capital expenditures	***($4,100 - 4,400)***	***($4,300 - 4,600)***
Dividends, capitalized interest, cash income taxes, etc.	($350 - 400)	***($500 - 600)***
Other	($500 - 600)	($250 - 300)
Projected Net Cash Change	***$1,250 - 1,300***	***$1,250 - 1,800***

(a) NYMEX natural gas prices have been updated for actual contract prices through February 2010 and NYMEX oil

prices have been updated for actual contract prices through January 2010.

(b) Excludes expenses associated with noncash stock compensation.

(c) Does not include gains or losses on interest rate derivatives.

(d) A non-GAAP financial measure. We are unable to provide a reconciliation to projected cash provided by operating

activities, the most comparable GAAP measure, because of uncertainties associated with projecting future

changes in assets and liabilities.

(e) Assumes NYMEX prices of $6.50 to $7.50 per mcf and $80.00 per bbl in 2010 and $7.00 to $8.00 per mcf and

$80.00 per bbl in 2011.

At December 31, 2009, the company had approximately $2.6 billion of cash and cash equivalents and additional borrowing capacity under its three revolving bank credit facilities.

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future natural gas and oil production. These strategies include:

1) Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
2) 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. On occasion, we make a three-way collar by selling an additional put option with the collar in exchange for a more favorable strike price on the collar. This eliminates the counterparty's downside exposure below the second put option.
3) 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.
4) Call options: Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from either party.
5) 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.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into natural gas and oil derivative transactions in order to mitigate a portion of its exposure to adverse market changes in natural gas and oil prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to natural gas and oil sales. All realized gains and losses from natural gas and oil derivatives are included in natural gas and oil sales in the month of related production. In accordance with generally accepted accounting principles, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these nonqualifying derivatives that occur prior to their maturity (i.e., because of temporary fluctuations in value) are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in natural gas and oil sales.

The company currently has the following open natural gas swaps in place and also has the following gains from lifted natural gas trades:

	Open Swaps (Bcf)	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production (Bcf)	Open Swap Positions as a % of Estimated Total Natural Gas Production		Total Gains from Lifted Trades ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q1 2010	***110***	***$ 7.53***				$ 35.9	
Q2 2010	***123***	***$ 7.43***				$ 37.9	
Q3 2010	***118***	***$* 7.60**				$ 65.7	
Q4 2010	***119***	***$ 7.75***				$ 65.2	
Total 2010(a)	***470***	***$ 7.58***	892	***53***	***%***	$ 204.7	$ 0.23
Total 2011(a)	***72***	***$ 8.71***	1,035	***7***	***%***	$ 62.7	$ 0.06

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at prices ranging from $5.50 to $6.75 covering 15 bcf in 2010 and $5.75 to $6.50 covering 24 bcf in 2011.

The company currently has the following open natural gas collars in place:

	Open Collars (Bcf)	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production (Bcf)	Open Collars as a % of Estimated Total Natural Gas Production	
Q1 2010	43	$ 6.49	$ 8.51			
Q2 2010	16	$ 7.04	$ 9.17			
Q3 2010	4	$ 7.60	$ 11.75			
Q4 2010	4	$ 7.60	$ 11.75			
Total 2010(a)	67	$ 6.75	$ 9.03	892	8	%
Total 2011	7	$ 7.70	$ 11.50	1,035	1	%

(a) Certain collar arrangements include three-way collars that include written put options with a strike price ranging from $4.25 to $4.35 covering 12 bcf in 2010.

The company currently has the following natural gas written call options in place:

	Call Options (Bcf)	**Avg. NYMEX Floor Price**	**Avg. Premium per mcf**	**Assuming Natural Gas Production (Bcf)**	**Call Options as a % of Estimated Total Natural Gas Production**
Q1 2010	28	$ 10.19	$ 1.47		
Q2 2010	38	$ 9.87	$ 1.11		
Q3 2010	43	$ 9.93	$ 0.98		
Q4 2010	43	$ 10.10	$ 0.98		
Total 2010	152	$ 10.01	$ 1.10	892	17 %
Total 2011	73	$ 10.25	$ 0.57	1,035	7 %

The company has the following natural gas basis protection swaps in place:

	Non-Appalachia Volume (Bcf)	NYMEX less(a)	Appalachia Volume (Bcf)	NYMEX plus(a)
2010	--	$ --	10	$ 0.26
2011	45	0.82	12	0.25
2012	43	0.85	--	--
Totals	88	$ 0.84	22	$ 0.26

(a) weighted average

The company also has the following crude oil swaps in place:

	Open Swaps (mbbls)	**Avg. NYMEX Strike Price**	**Assuming Oil Production (mbbls)**	**Open Swap Positions as a % of Estimated Total Oil Production**	**Total Gains (Losses) from Lifted Trades ($ millions)**	**Total Lifted Gains (Losses) per bbl of Estimated Total Oil Production**
Q1 2010	***2,250***	***$ 89.62***	***--***	***--***	$ (4.0)	--
Q2 2010	***2,275***	***$ 89.62***	***--***	***--***	$ (4.0)	--
Q3 2010	***2,300***	***$ 89.62***	***--***	***--***	$ (4.2)	--
Q4 2010	***2,300***	***$ 89.62***	***--***	***--***	$ (4.2)	--
Total 2010(a)	***9,125***	***$ 89.62***	***15,500***	***59 %***	$ (16.4)	***$ (1.06)***
Total 2011(a)	3,285	$ 96.09	***17,500***	***19 %***	$ 32.8	***$ 1.88***

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices of $60.00 covering 5 mmbbls and 1 mmbbls in 2010 and 2011, respectively.

Note: Not shown above are written call options covering 1 mmbbls of oil production in 2010 at a weighted average price of $101.25 per bbl for a weighted average discount of $1.93 per bbl and 5 mmbls of oil production in 2011 at a weighted average price of $101.54 per bbl for a weighted average premium of $3.29 per bbl.

SOURCE: Chesapeake Energy Corporation

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