NEWS
RELEASE

CHESAPEAKE ENERGY

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2009 Third Quarter

Company Reports 2009 Third Quarter Adjusted Net Income to Common Shareholders of $440 Million, or $0.70 per Fully Diluted Common Share, on Revenue of $1.8 Billion; Net Income Available to Common Shareholders Was $186 Million, or $0.30 per Fully Diluted Common Share Company Reports 2009 Third Quarter Production of 2.483 Bcfe per Day, an Increase of 1% over 2009 Second Quarter Production and 7% over 2008 Third Quarter Production Company Delivers 2009 Nine Month Drilling and Net Acquisition Costs of $0.78 per Mcfe

OKLAHOMA CITY--(BUSINESS WIRE)--Nov. 2, 2009-- Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operating results for the 2009 third quarter. For the quarter, Chesapeake reported net income to common shareholders of $186 million ($0.30 per fully diluted common share), operating cash flow of $1.118 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $707 million (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.811 billion and production of 228 billion cubic feet of natural gas equivalent (bcfe).

The company’s 2009 third quarter results include a realized natural gas and oil hedging gain of $687 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, Chesapeake generated adjusted net income to common shareholders for the 2009 third quarter of $440 million ($0.70 per fully diluted common share) and adjusted ebitda of $1.133 billion. The excluded items and their effects on 2009 third quarter reported results are detailed as follows:

- a net unrealized noncash after-tax mark-to-market loss of $166 million resulting from the company’s natural gas, oil and interest rate hedging programs; and
- a combined after-tax charge of $88 million related primarily to the impairment of certain midstream assets contributed to the newly formed joint venture with Global Infrastructure Partners, a loss on the sale of certain gathering systems and a loss 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 15 - 19 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake’s key results during the 2009 third quarter and compares them to results during the 2009 second quarter and the 2008 third quarter.

	Three Months Ended		
	9/30/09	6/30/09	9/30/08[(a)]
Average daily production (in mmcfe)	2,483	2,453	2,321
Natural gas as % of total production	92	92	92
Natural gas production (in bcf)	210.3	204.3	196.7
Average realized natural gas price ($/mcf) [(b)]	6.04	5.56	8.02
Oil production (in mbbls)	3,027	3,152	2,810
Average realized oil price ($/bbl) [(b)]	66.42	56.72	75.74
Natural gas equivalent production (in bcfe)	228.5	223.2	213.5
Natural gas equivalent realized price ($/mcfe) [(b)]	6.44	5.89	8.38
Natural gas and oil marketing income ($/mcfe)	.13	.14	.11
Service operations income (loss) ($/mcfe)	.00	(.01)	.04
Production expenses ($/mcfe)	(.96)	(.95)	(1.12)
Production taxes ($/mcfe)	(.11)	(.11)	(.41)
General and administrative costs ($/mcfe) [(c)]	(.32)	(.25)	(.38)
Stock-based compensation ($/mcfe)	(.09)	(.09)	(.12)
DD&A of natural gas and oil properties ($/mcfe)	(1.29)	(1.32)	(2.25)
D&A of other assets ($/mcfe)	(.27)	(.26)	(.22)
Interest expense ($/mcfe) [(b)]	(.28)	(.29)	(.20)
Operating cash flow ($ in millions) [(d)]	1,118	1,006	1,245
Operating cash flow ($/mcfe)	4.89	4.51	5.83
Adjusted ebitda ($ in millions) [(e)]	1,133	1,030	1,386
Adjusted ebitda ($/mcfe)	4.96	4.62	6.49
Net income to common shareholders ($ in millions)	186	237	3,291
Earnings per share – assuming dilution ($)	.30	.39	5.62
Adjusted net income to common shareholders ($ in millions) [(f)]	440	377	495
Adjusted earnings per share – assuming dilution ($)	.70	.62	.87

(a) Reflects the adoption and retrospective application of ASC 470-20, *Debt with Conversion and Other Options*

(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 noncash stock-based compensation

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

(e) Defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on page 19

(f) Defined as net income available to common shareholders, as adjusted to remove the effects of certain items detailed on page 17

2009 Third Quarter Average Daily Production Increases 1% over 2009 Second Quarter Production and 7% over 2008 Third Quarter Production

As announced on October 29, 2009, the company's daily production for the 2009 third quarter averaged 2.483 bcfe, an increase of 30 million cubic feet of natural gas equivalent (mmcfe), or 1%, over the 2.453 bcfe produced per day in the 2009 second quarter and an increase of 162 mmcfe, or 7%, over the 2.321 bcfe produced per day in the 2008 third quarter. Adjusted for the company's 2009 voluntary production curtailments due to low natural gas prices and involuntary production curtailments due to pipeline repairs in the Fayetteville Shale (which together averaged approximately 45 mmcfe per day during the 2009 third quarter), the company's 2009 and third and fourth quarter 2008 volumetric production payment transactions (which combined averaged approximately 125 mmcfe per day during the 2009 third quarter) and the estimated impact from various divestitures (which would have averaged approximately 105 mmcfe per day during the 2009 third quarter), Chesapeake's sequential and year-over-year production growth rates would have been 2% and 14%, respectively, after making similar adjustments to prior quarters.

Chesapeake's average daily production for the 2009 third quarter of 2.483 bcfe consisted of 2.286 billion cubic feet of natural gas (bcf) and 32,902 barrels of oil and natural gas liquids (bbls). The company's 2009 third quarter production of 228.5 bcfe was comprised of 210.3 bcf (92% on a natural gas equivalent basis) and 3.0 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis).

The company anticipates delivering full-year production growth of approximately 5-6% in 2009, 8-10% in 2010 and 12-14% in 2011.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2009 third quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $6.04 per thousand cubic feet (mcf) and $66.42 per bbl, for a realized natural gas equivalent price of $6.44 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas and oil hedging activities during the 2009 third quarter generated a $3.20 gain per mcf and a $3.95 gain per bbl for a 2009 third quarter realized hedging gain of $687 million, or $3.00 per mcfe. Without realized hedging gains, the company's average realized prices for the 2009 third quarter would have been $2.84 per mcf and $62.47 per bbl, for a natural gas equivalent price of $3.44 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2009 third quarter were a negative $0.55 per mcf and a negative $5.83 per bbl.

By comparison, average prices realized during the 2008 third quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.02 per mcf and $75.74 per bbl, for a realized natural gas equivalent price of $8.38 per mcfe. Realized losses from natural gas and oil hedging activities during the 2008 third quarter generated a $0.71 loss per mcf and a $37.79 loss per bbl for a 2008 third quarter realized hedging loss of $246 million, or $1.15 per mcfe. Without realized hedging losses, the company's average realized prices for the 2008 third quarter would have been $8.73 per mcf and $113.53 per bbl, for a natural gas equivalent price of $9.54 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2008 third quarter were a negative $1.52 per mcf and a negative $4.46 per bbl.

The following tables summarize Chesapeake's open hedge position through swaps and collars as of November 2, 2009. 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 November 2, 2009

	Natural Gas			**Oil**		
Year	**% Hedged**		**$ NYMEX**	**% Hedged**		**$ NYMEX**
Q4 2009	53	%	6.85	36	%	87.05
2010	14	%	9.53	38	%	90.25
2011	2	%	9.86	8	%	104.75

Open Natural Gas Collar Positions as of November 2, 2009

Year	% Hedged		Average Floor $ NYMEX	Average Ceiling $ NYMEX
Q4 2009	25	%	7.34	8.88
2010	8	%	6.75	9.03
2011	1	%	7.70	11.50

Note: Certain open natural gas swap positions include knockout swaps with knockout provisions at $6.00 per mcf covering 1 bcf for the remainder of 2009, or less than 1% of the company's natural gas swap positions remaining in 2009, $5.45 to $6.75 per mcf covering 70 bcf in 2010, or approximately 55% of the company's natural gas swap positions in 2010; and $5.75 to $6.50 per mcf covering 24 bcf in 2011, or virtually all of the company's natural gas swap positions in 2011. Certain open natural gas collar positions include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 per mcf covering 11 bcf for the remainder of 2009 and ranging from $4.25 to $5.50 per mcf covering 26 bcf in 2010, or approximately 20% and 40% of the company's natural gas collar positions remaining in 2009 and 2010, respectively. Also, certain open oil swap positions include knockout swaps with knockout provisions at prices ranging from $50 to $60 per bbl covering 1 mmbbls for the remainder of 2009 and $60 per bbl covering 5 mmbbls and 1 mmbbls in 2010 and 2011, respectively, or virtually all of the company's oil swap positions remaining in 2009, 2010 and 2011.

As of October 30, 2009, Chesapeake's natural gas and oil hedging positions with 14 different counterparties had a positive mark-to-market value of approximately $290 million. The company's realized cash hedging gains for 2009 have been $1.8 billion and since January 1, 2001 have been $3.9 billion.

The company's updated forecasts for 2009, 2010 and 2011 are attached to this release in an Outlook dated November 2, 2009, labeled as Schedule "A," which begins on page 20. This Outlook has been changed from the Outlook dated October 13, 2009, attached as Schedule "B," which begins on page 25, to reflect various updated information.

Chesapeake's Proved Natural Gas and Oil Reserves Decrease by 0.5 Tcfe in the 2009 Third Quarter to 12.0 Tcfe Due to Natural Gas Price Decline; Company Delivers Drilling and Net Acquisition Costs of $0.78 per Mcfe for the First Three Quarters of 2009; Company Record Set for Organic Proved Reserve Additions over a Nine Month Period

Chesapeake began the 2009 third quarter with estimated proved reserves of 12.525 trillion cubic feet of natural gas equivalent (tcfe) and ended the 2009 third quarter with 11.994 tcfe, a decrease of 531 bcfe, or 4%. The quarter's reserve movement included 228 bcfe of production, 664 bcfe of extensions, 325 bcfe of positive performance revisions, 1.191 tcfe of negative revisions resulting from natural gas price decreases between June 30, 2009 and September 30, 2009 and 101 bcfe of net divestitures.

Chesapeake's total drilling and net acquisition costs for the 2009 third quarter were $0.34 per mcfe. This calculation excludes costs of $516 million for the acquisition of unproved properties and leasehold, $1.124 billion for the divestiture of unproved properties and leasehold, $151 million for capitalized interest on unproved properties, $22 million for geological and geophysical expenditures and asset retirement obligations, and also excludes downward revisions of proved reserves from lower natural gas prices. Excluding these items and proved reserve acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during the 2009 third quarter were $0.64 per mcfe, giving effect to the benefit of $379 million in drilling carries associated with the Haynesville ($146 million), Fayetteville ($186 million) and Marcellus ($47 million) joint ventures. A complete reconciliation of 2009 third quarter proved reserves and finding and acquisition costs is presented on page 11 of this release.

During the first three quarters of 2009, Chesapeake's estimated proved reserves decreased 57 bcfe, or 0.5%, from 12.051 tcfe at year-end 2008. Year to date, Chesapeake has replaced 665 bcfe of production with an estimated 608 bcfe of new proved reserves for a reserve replacement rate of 91%. The reserve movement for the nine months included 1.455 tcfe of extensions, 1.503 tcfe of positive performance revisions, 2.164 tcfe of downward revisions resulting from a decrease in natural gas prices between December 31, 2008 and September 30, 2009 and 186 bcfe of net divestitures. Chesapeake's 2.958 tcfe of extensions and performance revisions in the first three quarters of 2009 set a company record for the highest level of organic proved reserve additions over a nine-month period. Based on current strip natural gas pricing, the company expects to recover at year-end 2009 approximately half of the 2.164 tcfe of its proved reserves that have been revised downward during the first three quarters of 2009 as a result of the decline in natural gas prices and to recover by year-end 2010 all or substantially all of these price-related revisions.

Chesapeake's total drilling and net acquisition costs for the first three quarters of 2009 were $0.78 per mcfe. This calculation excludes costs of $1.262 billion for the acquisition of unproved properties and leasehold, $1.124 billion for the divestiture of unproved properties and leasehold, $464 million for capitalized interest on unproved properties, $117 million for geological and geophysical expenditures and asset retirement obligations, and also excludes downward revisions of proved reserves from lower natural gas prices. Excluding these items and proved reserve acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during the first three quarters of 2009 were $0.86 per mcfe, giving effect to the benefit of $959 million in drilling carries associated with the Haynesville ($350 million), Fayetteville ($524 million) and Marcellus ($85 million) joint ventures. A complete reconciliation of the first three quarters of 2009 proved reserves and finding and acquisition costs is presented on page 12 of this release.

Chesapeake continued the industry's most active drilling program during the first three quarters of 2009, drilling 853 gross operated wells (624 net wells with an average working interest of 73%) and participating in another 864 gross wells operated by other companies (76 net wells with an average working interest of 9%). The company's drilling success rate was 99% for company-operated wells and 98% for non-operated wells. During the first three quarters of 2009, Chesapeake invested $2.211 billion in operated wells (using an average of 102 operated rigs) and $330 million in non-operated wells (using an average of 57 non-operated rigs) for total drilling, completing and equipping costs of $2.541 billion (net of carries).

As of September 30, 2009, the present value of future net cash flows, discounted at 10% per year, of Chesapeake's estimated proved reserves (PV-10) was $7.596 billion based on NYMEX quarter-end prices of $3.30 per mcf and $70.21 per bbl. Chesapeake's PV-10 changes by approximately $400 million for every $0.10 per mcf change in natural gas prices and approximately $60 million for every $1.00 per bbl change in oil prices.

By comparison, the December 31, 2008 PV-10 of the company's proved reserves was

$15.601 billion ($11.833 billion applying the ASC 932 standardized measure) based on NYMEX year-end prices of $5.71 per mcf and $44.61 per bbl. The September 30, 2008 PV-10 of the company's proved reserves was $24.404 billion based on NYMEX quarter-end prices of $7.12 per mcf and $100.66 per bbl.

The company calculates the standardized measure of future net cash flows in accordance with ASC 932 only at year end because applicable income tax information on properties, including recently acquired natural gas and oil interests, is not readily available at other times during the year. As a result, the company is not able to reconcile the interim period-end PV-10 values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects.

In addition to the PV-10 value of its proved reserves and the very significant value of its undeveloped leasehold, particularly in the Haynesville, Marcellus, Barnett and Fayetteville Shale plays and in the Colony and Texas Panhandle Granite Wash plays, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments and other noncurrent assets) was $6.5 billion as of September 30, 2009, $5.8 billion as of December 31, 2008 and $4.9 billion as of September 30, 2008.

Conference Call Information

A conference call to discuss this release has been scheduled for Tuesday morning, November 3, 2009, at 9:00 a.m. EST. The telephone number to access the conference call is **913-227-1352** or toll-free **866-293-8969**. The passcode for the call is **4137448**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 9:00 a.m. EST. For those unable to participate in the conference call, a replay will be available for audio playback from 1:00 p.m. EST on November 3, 2009 through midnight EST on November 17, 2009. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **4137448**. 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 our website. The webcast of the conference call will be available on our 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 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 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 2008 Form 10-K and 2009 second quarter Form 10-Q filed with the U.S. Securities and Exchange Commission on March 2, 2009 and August 10, 2009, respectively. These risk factors include the volatility of natural gas *and oil prices; the limitations our level of indebtedness may have on our financial flexibility; impacts the current economic downturn may have on our business and financial condition; 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; exploration and development drilling that does not result in commercially productive reserves; 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; uncertainties in evaluating natural gas and oil reserves of acquired properties and potential liabilities; the negative impact lower natural gas and oil prices could have on our ability to borrow; drilling and operating risks, including potential environmental liabilities; transportation capacity constraints and interruptions that could adversely affect our cash flow; potential increased operating costs resulting from proposed legislative and regulatory changes affecting our operations; 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 one of the leading producers of natural gas in the U.S. Headquartered in Oklahoma City, the company's operations are focused on the development of onshore unconventional and conventional natural gas in the U.S. in the Barnett Shale, Haynesville Shale, Fayetteville Shale, Marcellus Shale, Anadarko Basin, Arkoma Basin, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and East Texas regions of the United States. 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:	**September 30, 2009**		**September 30, 2008 (a)**	
	$	**$/mcfe**	**$**	**$/mcfe**
REVENUES:				
Natural gas and oil sales	1,187	5.20	6,408	30.01
Marketing, gathering and compression sales	575	2.52	1,038	4.86
Service operations revenue	49	0.21	45	0.21
Total Revenues	1,811	7.93	7,491	35.08
OPERATING COSTS:				
Production expenses	218	0.96	239	1.12
Production taxes	25	0.11	87	0.41
General and administrative expenses	95	0.42	108	0.51
Marketing, gathering and compression expenses	546	2.39	1,014	4.75
Service operations expense	49	0.21	37	0.17

Natural gas and oil depreciation, depletion and amortization	295	1.29	480	2.25
Depreciation and amortization of other assets	62	0.27	48	0.22
Impairment of other assets	86	0.38	—	—
Loss on sale of other property and equipment	38	0.16	—	—
Total Operating Costs	1,414	6.19	2,013	9.43
INCOME FROM OPERATIONS	397	1.74	5,478	25.65
OTHER INCOME (EXPENSE):				
Other income (expense)	(30)	(0.14)	(12)	(0.06)
Interest expense	(43)	(0.19)	(34)	(0.16)
Loss on exchanges of Chesapeake debt	(17)	(0.07)	(31)	(0.14)
Total Other Income (Expense)	(90)	(0.40)	(77)	(0.36)
INCOME BEFORE INCOME TAXES	307	1.34	5,401	25.29
Income Tax Expense:				
Current	—	—	193	0.90
Deferred	115	0.50	1,886	8.84
Total Income Tax Expense	115	0.50	2,079	9.74
NET INCOME	192	0.84	3,322	15.55
Net income attributable to noncontrolling interest	—	—	—	—
NET INCOME ATTRIBUTABLE TO CHESAPEAKE ENERGY	192	0.84	3,322	15.55
Preferred stock dividends	(6)	(0.03)	(6)	(0.03)
Loss on conversion/exchange of preferred stock	—	—	(25)	(0.11)
NET INCOME AVAILABLE TO CHESAPEAKE ENERGY COMMON SHAREHOLDERS	186	0.81	3,291	15.41
EARNINGS PER COMMON SHARE:				
Basic	$ 0.30		$ 5.94	
Assuming dilution	$ 0.30		$ 5.62	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	619		554	
Assuming dilution	626		588	

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in millions, except per-share and unit data)
(unaudited)

NINE MONTHS ENDED:	**September 30, 2009**		**September 30, 2008 [(a)]**	
	$	**$/mcfe**	**$**	**$/mcfe**
REVENUES:				
Natural gas and oil sales	3,681	5.54	5,587	8.87
Marketing, gathering and compression sales	1,660	2.50	2,934	4.66

Service operations revenue	139	0.20	127	0.20
Total Revenues	5,480	8.24	8,648	13.73
OPERATING COSTS:				
Production expenses	670	1.01	658	1.04
Production taxes	71	0.11	250	0.40
General and administrative expenses	259	0.39	288	0.46
Marketing, gathering and compression expenses	1,569	2.36	2,864	4.55
Service operations expense	136	0.20	104	0.16
Natural gas and oil depreciation, depletion and amortization	1,037	1.56	1,518	2.41
Depreciation and amortization of other assets	177	0.27	124	0.20
Impairment of natural gas and oil properties and other assets	9,721	14.62	—	—
Loss on sale of other property and equipment	38	0.05	—	—
Restructuring costs	34	0.05	—	—
Total Operating Costs	13,712	20.62	5,806	9.22
INCOME (LOSS) FROM OPERATIONS	(8,232)	(12.38)	2,842	4.51
OTHER INCOME (EXPENSE):				
Other income (expense)	(25)	(0.04)	(23)	(0.03)
Interest expense	(52)	(0.08)	(186)	(0.30)
Impairment of investments	(162)	(0.24)	—	—
Loss on exchanges of Chesapeake debt	(19)	(0.03)	(31)	(0.05)
Total Other Income (Expense)	(258)	(0.39)	(240)	(0.38)
INCOME (LOSS) BEFORE INCOME TAXES	(8,490)	(12.77)	2,602	4.13
Income Tax Expense (Benefit):				
Current	1	—	196	0.31
Deferred	(3,185)	(4.79)	806	1.28
Total Income Tax Expense (Benefit)	(3,184)	(4.79)	1,002	1.59
NET INCOME (LOSS)	(5,306)	(7.98)	1,600	2.54
Net income (loss) attributable to noncontrolling interest	—	—	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE ENERGY	(5,306)	(7.98)	1,600	2.54
Preferred stock dividends	(18)	(0.03)	(27)	(0.04)
Loss on conversion/exchange of preferred stock	—	—	(67)	(0.11)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE ENERGY COMMON SHAREHOLDERS	(5,324)	(8.01)	1,506	2.39
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (8.78)		$ 2.88	
Assuming dilution	$ (8.78)		$ 2.76	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	606		523	
Assuming dilution	606		557	

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
($ in millions)
(unaudited)

	September 30, 2009	December 31, 2008 [(a)]
Cash and cash equivalents	$ 520	$ 1,749
Other current assets	1,988	2,543
Total Current Assets	2,508	4,292
Property and equipment (net)	26,378	33,308
Other assets	833	993
Total Assets	$ 29,719	$ 38,593
Current liabilities	$ 2,514	$ 3,621
Long-term debt, net [(b)]	12,073	13,175
Asset retirement obligation	282	269
Other long-term liabilities	705	311
Deferred tax liability	1,316	4,200
Total Liabilities	16,890	21,576
Chesapeake Energy Stockholders' Equity	11,978	17,017
Noncontrolling interest	851	—
Total equity	12,829	17,017
Total Liabilities & Equity	$ 29,719	$ 38,593
Common Shares Outstanding (in millions)	645	607

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION
($ in millions)
(unaudited)

	September 30, 2009	% of Total Book Capitalization		December 31, 2008((a))	% of Total Book Capitalization	
Total debt, net cash [(b)]	$ 11,553	47	%	$ 11,426	40	%
Stockholders' equity	11,978	49	%	17,017	60	%
Noncontrolling interest	851	4	%	—	—	
Total	$ 24,382	100	%	$ 28,443	100	%

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

(b) Includes $1.630 billion of borrowings under the company's $3.5 billion revolving bank credit facility, the company's $250 million midstream revolving bank credit facility and the company's $500 million midstream joint venture revolving bank credit facility. At September 30, 2009, the company had $2.596 billion of additional borrowing capacity under these three revolving bank credit facilities.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
($ in millions, except per-unit data)
(unaudited)

THREE MONTHS ENDED SEPTEMBER 30, 2009	Cost	Reserves (in bcfe)	$/mcfe
Exploration and development costs	$ 631	989 [a]	0.64
Acquisition of proved properties	43	22	1.96
Divestitures of proved properties	(379)	(123)	3.08
Other	10 [b]	—	—
Drilling and net acquisition cost	305	888	0.34
Revisions – price	—	(1,191)	—
Acquisition of unproved properties and leasehold	516	—	—
Divestiture of unproved properties and leasehold	(1,124)	—	—
Capitalized interest	151 [c]	—	—
Geological and geophysical costs	23	—	—
Leasehold, capitalized interest, geological and geophysical	(434)	—	—
Subtotal	(129)	(303)	0.43
Asset retirement obligation and other	(1)	—	—
Total	$ (130)	(303)	0.43

(a) Includes 325 bcfe of performance revisions (211 bcfe relating to infill drilling and increased density locations and 114 bcfe of other performance-related revisions) and excludes downward revisions of 1.191 tcfe resulting primarily from natural gas price decreases between June 30, 2009 and September 30, 2009.

(b) Includes adjustments to certain acquisitions and divestitures that closed during prior periods.

(c) Includes capitalized interest on unproved leasehold and geological and geophysical costs.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
THREE MONTHS ENDED SEPTEMBER 30, 2009
(unaudited)

	Bcfe
Beginning balance, 07/01/09	12,525
Production	(228)
Extensions and discoveries	664
Revisions – performance	325
Revisions – price	(1,191)
Acquisitions	22
Divestitures	(123)
Ending balance, 09/30/09	11,994
Reserve replacement	(303)
Reserve replacement ratio [a]	(133)%

(a) The company uses the reserve replacement ratio as an indicator of the company's ability to replenish production volumes and grow its reserves. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. The ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not embed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
($ in millions, except per-unit data)
(unaudited)

NINE MONTHS ENDED SEPTEMBER 30, 2009	Cost	Reserves (in bcfe)	$/mcfe
Exploration and development costs	$ 2,541	2,958[a]	0.86
Acquisition of proved properties	60	35	1.70
Divestitures of proved properties	(572)	(221)	2.58
Other	128[b]	—	—
Drilling and net acquisition cost	2,157	2,772	0.78
Revisions – price	—	(2,164)	—
Acquisition of unproved properties and leasehold	1,262	—	—
Divestiture of unproved properties and leasehold	(1,124)	—	—
Capitalized interest	464[c]	—	—
Geological and geophysical costs	120	—	—
Leasehold, capitalized interest, geological and geophysical	722	—	—
Subtotal	2,879	608	4.74
Asset retirement obligation and other	(3)	—	—
Total	$ 2,876	608	4.73

(a) Includes 1.503 tcfe of performance revisions (703 bcfe relating to infill drilling and increased density locations and 800 bcfe of other performance-related revisions) and excludes downward revisions of 2.164 tcfe resulting primarily from natural gas price decreases between December 31, 2008 and September 30, 2009.

(b) Includes adjustments to certain acquisitions and divestitures that closed during prior periods.

(c) Includes capitalized interest on unproved leasehold and geological and geophysical costs.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
NINE MONTHS ENDED SEPTEMBER 30, 2009
(unaudited)

	Bcfe
Beginning balance, 01/01/09	12,051
Production	(665)
Extensions and discoveries	1,455
Revisions – performance	1,503
Revisions – price	(2,164)
Acquisitions	35
Divestitures	(221)
Ending balance, 09/30/09	11,994
Reserve replacement	608
Reserve replacement ratio [a]	91 %

(a) The company uses the reserve replacement ratio as an indicator of the company's ability to replenish production volumes and grow its reserves. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. The ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not embed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

CHESAPEAKE ENERGY CORPORATION
SUPPLEMENTAL DATA – NATURAL GAS AND OIL SALES AND INTEREST EXPENSE
(unaudited)

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2009	**2008**	**2009**	**2008**
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 596	$ 1,717	$ 1,819	$ 5,046
Natural gas derivatives – realized gains (losses)	675	(140)	1,771	(174)
Natural gas derivatives – unrealized gains (losses)	(275)	3,854	(398)	325
Total Natural Gas Sales	996	5,431	3,192	5,197
Oil sales	189	319	461	915
Oil derivatives – realized gains (losses)	12	(106)	31	(280)
Oil derivatives – unrealized gains (losses)	(10)	764	(3)	(245)
Total Oil Sales	191	977	489	390
Total Natural Gas and Oil Sales	$ 1,187	$ 6,408	$ 3,681	$ 5,587
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 2.84	$ 8.73	$ 2.98	$ 8.71
Oil ($ per bbl)	$ 62.47	$ 113.53	$ 50.97	$ 109.28
Natural gas equivalent ($ per mcfe)	$ 3.44	$ 9.54	$ 3.43	$ 9.47
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 6.04	$ 8.02	$ 5.88	$ 8.41
Oil ($ per bbl)	$ 66.42	$ 75.74	$ 54.37	$ 75.82
Natural gas equivalent ($ per mcfe)	$ 6.44	$ 8.38	$ 6.14	$ 8.75
Interest Expense (Income) ($ in millions): [a]				
Interest	$ 70	$ 37	$ 177	$ 194
Derivatives – realized (gains) losses	(7)	5	(19)	1
Derivatives – unrealized (gains) losses	(20)	(8)	(106)	(9)
Total Interest Expense	$ 43	$ 34	$ 52	$ 186

(a) 2008 data adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options.*

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED CASH FLOW DATA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	**September 30, 2009**	**September 30, 2008** [a]
Beginning cash	$ 554	$ —

Cash provided by operating activities	$ 1,132	$ 1,588
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	$ (675)	$ (1,686)
Acquisitions of proved and unproved properties and leasehold	(495)	(4,466)
Divestitures of proved and unproved properties, leasehold and VPPs	1,501	5,013
Additions to other property and equipment	(381)	(740)
Proceeds from sales of drilling rigs and compressors	—	76
Capitalized interest on unproved properties	(151)	(166)
Other	12	59
Total cash used in investing activities	$ (189)	$ (1,910)
Cash (used in) provided by financing activities	$ (977)	$ 2,286
Ending cash	$ 520	$ 1,964

NINE MONTHS ENDED:	**September 30, 2009**	**September 30, 2008** [a]
Beginning cash	$ 1,749	$ 1
Cash provided by operating activities	$ 3,131	$ 4,387
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	$ (2,767)	$ (4,621)
Acquisitions of proved and unproved properties and leasehold	(907)	(7,301)
Divestitures of proved and unproved properties, leasehold and VPPs	1,729	5,876
Additions to other property and equipment	(1,362)	(1,969)
Proceeds from sales of drilling rigs and compressors	68	160
Capitalized interest on unproved properties	(464)	(390)
Other	49	(38)
Total cash used in investing activities	$ (3,654)	$ (8,283)
Cash (used in) provided by financing activities	$ (706)	$ 5,859
Ending cash	$ 520	$ 1,964

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	**September 30, 2009**	**June 30, 2009**	**September 30, 2008** [a]
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,132	$ 737	$ 1,588
Adjustments:			
Changes in assets and liabilities	(14)	269	(343)
OPERATING CASH FLOW [b]	$ 1,118	$ 1,006	$ 1,245

THREE MONTHS ENDED:	**September 30, 2009**	**June 30, 2009**	**September 30, 2008** [a]

NET INCOME	$ 192	$ 243	$ 3,322
Income tax expense	115	145	2,079
Interest expense	43	22	34
Depreciation and amortization of other assets	62	58	48
Natural gas and oil depreciation, depletion and amortization	295	295	480
EBITDA [c]	$ 707	$ 763	$ 5,963

THREE MONTHS ENDED:	**September 30, 2009**	**June 30, 2009**	**September 30, 2008 [a]**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,132	$ 737	$ 1,588
Changes in assets and liabilities	(14)	269	(343)
Interest expense	43	22	34
Unrealized gains (losses) on natural gas and oil derivatives	(285)	(216)	4,618
Impairment of other assets	(86)	(5)	—
Loss on sale of other property and equipment	(38)	—	—
Restructuring costs	15	(29)	—
Other non-cash items	(60)	(15)	66
EBITDA [c]	$ 707	$ 763	$ 5,963

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

(b) 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.

(c) 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 OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

NINE MONTHS ENDED:	September 30, 2009	September 30, 2008 [a]
CASH PROVIDED BY OPERATING ACTIVITIES	$ 3,131	$ 4,387
Adjustments:		
Changes in assets and liabilities	(8)	(142)
OPERATING CASH FLOW [b]	$ 3,123	$ 4,245

NINE MONTHS ENDED:	September 30, 2009	September 30, 2008 [a]
NET INCOME (LOSS)	$ (5,306)	$ 1,600
Income tax expense (benefit)	(3,184)	1,002
Interest expense	52	186
Depreciation and amortization of other assets	177	124
Natural gas and oil depreciation, depletion and amortization	1,037	1,518
EBITDA [c]	$ (7,224)	$ 4,430

NINE MONTHS ENDED:	September 30, 2009	September 30, 2008 [a]
CASH PROVIDED BY OPERATING ACTIVITIES	$ 3,131	$ 4,387
Changes in assets and liabilities	(8)	(142)
Interest expense	52	186
Unrealized gains (losses) on natural gas and oil derivatives	(401)	80
Impairment of natural gas and oil properties and other assets	(9,721)	—
Loss on sale of other property and equipment	(38)	—
Impairment of investments	(153)	—
Restructuring costs	(14)	—
Other non-cash items	(72)	(81)
EBITDA [c]	$ (7,224)	$ 4,430

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

(b) 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.

(c) 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 NET INCOME AVAILABLE TO COMMON SHAREHOLDERS
($ in millions, except per-share data)
(unaudited)

THREE MONTHS ENDED:	**September 30, 2009**	**June 30, 2009**	**September 30, 2008 [a]**
Net income available to common shareholders	$ 186	237	$ 3,291
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	166	109	(2,846)
Impairment other assets, net of tax	54	3	—
Loss on sale of other property and equipment, net of tax	24	—	—
Impairment of investments, net of tax	—	6	—
Restructuring costs, net of tax	—	21	—
Loss on exchanges of Chesapeake debt, net of tax	10	1	19
Consent fees on senior notes, net of tax	—	—	6
Loss on conversions or exchanges of preferred stock	—	—	25
Adjusted net income available to common shareholders [b]	440	377	495
Preferred stock dividends	6	6	6
Interest on contingent convertible notes, net of tax	—	—	10
Total adjusted net income	$ 446	$ 383	$ 511
Weighted average fully diluted shares outstanding [c]	637	622	589
Adjusted earnings per share assuming dilution [b]	$ 0.70	$ 0.62	$ 0.87

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

(b) Adjusted net income available to common shareholders 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 shareholders 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 shareholders 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.

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

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON SHAREHOLDERS
($ in millions, except per-share data)
(unaudited)

NINE MONTHS ENDED:	September 30, 2009	September 30, 2008 [(a)]
Net income (loss) available to common shareholders	$ (5,324)	$ 1,506
Adjustments:		
Unrealized (gains) losses on derivatives, net of tax	184	(55)
Impairment of natural gas and oil properties and other assets, net of tax	6,076	—
Loss on sale of other property and equipment, net of tax	24	—
Impairment of investments, net of tax	102	—
Restructuring cost, net of tax	21	—
Loss on exchanges of Chesapeake debt, net of tax	11	19
Consent fees on senior notes, net of tax	—	6
Loss on conversions or exchanges of preferred stock	—	67
Adjusted net income available to common shareholders [(b)]	1,094	1,543
Preferred stock dividends	18	27
Interest on contingent convertible notes, net of tax	—	12
Total adjusted net income	$ 1,112	$ 1,582
Weighted average fully diluted shares outstanding [(c)]	625	564
Adjusted earnings per share assuming dilution[(b)]	$ 1.78	$ 2.81

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

(b) Adjusted net income available to common shareholders 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 shareholders 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 shareholders 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.

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

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EBITDA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	September 30, 2009	June 30, 2009	September 30, 2008 [(a)]

EBITDA	$ 707	$ 763	$ 5,963
Adjustments, before tax:			
Unrealized (gains) losses on natural gas and oil derivatives	285	216	(4,618)
Loss on exchanges of Chesapeake debt	17	2	31
Impairment other assets	86	5	—
Loss on sale of other property and equipment	38	—	—
Impairment of investments	—	10	—
Restructuring costs	—	34	—
Consent fees on senior notes	—	—	10
Adjusted ebitda (b)	$ 1,133	$ 1,030	$ 1,386

NINE MONTHS ENDED:	**September 30, 2009**	**September 30, 2008** (a)
EBITDA	$ (7,224)	$ 4,430
Adjustments, before tax:		
Unrealized (gains) losses on natural gas and oil derivatives	401	(80)
Loss on exchanges of Chesapeake debt	19	31
Impairment of natural gas and oil properties and other assets	9,721	—
Loss on sale of other property and equipment	38	—
Impairment of investments	162	—
Restructuring costs	34	—
Consent fees on senior notes	—	10
Adjusted ebitda (b)	$ 3,151	$ 4,391

(a) Adjusted for the retrospective application of ASC 470-20, *Debt with Conversion and Other Options*.

(b) 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.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF NOVEMBER 2, 2009

Years Ending December 31, 2009, 2010 and 2011

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of November 2, 2009, we are using the following key assumptions in our projections for 2009, 2010 and 2011.

The primary changes from our October 13, 2009 Outlook are in ***italicized bold*** and are explained as follows:

1) Projected effects of changes in our hedging positions have been updated;

2) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been updated; and

3) Our cash flow projections have been updated.

	Year Ending 12/31/2009	**Year Ending 12/31/2010**	**Year Ending 12/31/2011**
Estimated Production:			
Natural gas – bcf	815 – 825	882 – 902	1,007 – 1,027
Oil – mbbls	12,000	12,500	13,000
Natural gas equivalent – bcfe	885 – 895	957 – 977	1,085 – 1,105
Daily natural gas equivalent midpoint – mmcfe	2,440	2,650	3,000
Year-over-year estimated production increase	5 – 6%	8 – 10%	12 – 14%
Year-over-year estimated production increase excluding divestitures and curtailments	9 – 10%	10 – 12%	13 – 15%
NYMEX Prices [(a)] (for calculation of realized hedging effects only):			
Natural gas - $/mcf	***$3.91***	$7.00	$7.50
Oil - $/bbl	$57.75	$80.00	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	***$2.97***	$0.85	$0.22
Oil - $/bbl	***$3.78***	$1.99	$5.71
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	20 – 30%	15 – 25%	15 – 25%
Oil - $/bbl	7 – 10%	7 – 10%	7 – 10%
Operating Costs per Mcfe of Projected Production:			
Production expense	$1.10 – 1.20	$0.90 – 1.10	$0.90 – 1.10
Production taxes (~ 5% of O&G revenues)[(b)]	$0.20 – 0.25	$0.30 – 0.35	$0.30 – 0.35
General and administrative[(c)]	$0.33 – 0.37	$0.33 – 0.37	$0.33 – 0.37
Stock-based compensation (non-cash)	$0.10 – 0.12	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	$1.50 – 1.70	$1.50 – 1.70	$1.50 – 1.70
Depreciation of other assets	$0.25 – 0.30	$0.20 – 0.25	$0.20 – 0.25
Interest expense[(d)]	$0.30 – 0.35	$0.35 – 0.40	$0.35 – 0.40
Other Income per Mcfe:			
Marketing, gathering and compression net margin	$0.10 – 0.12	$0.07 – 0.09	$0.07 – 0.09
Service operations net margin	$0.04 – 0.06	$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)	37.5%	39%	39%
Equivalent Shares Outstanding (in millions):			
Basic	610 – 615	625 – 630	635 – 640
Diluted	625 – 630	640 – 645	645 – 650

	Year Ending 12/31/2009	**Year Ending 12/31/2010**	**Year Ending 12/31/2011**

Cash Flow Projections ($ in millions):			
Operating cash flow before changes in assets and liabilities[(e)(f)]	$3,700 – 3,750	$4,350 – 5,050	$4,750 – 5,450
Net leasehold and producing property transactions	$750 – 900	$1,000 – 1,350	$900 – 1,250
Drilling capital expenditures	($3,150 – 3,350)	($4,400 – 4,700)	($4,600 – 4,900)
Dividends, senior notes redemption, capitalized interest, cash income taxes, etc.	($600 – 825)	***($400 – 500)***	($450 – 550)
Other	($375 – 550)	($225 – 300)	($50 – 125)
Projected Net Cash Change	($75) – 325	***$325 – 900***	***$550 – 1,125***

At September 30, 2009, the company had $3.1 billion of cash and cash equivalents and additional borrowing capacity under its three revolving bank credit facilities.

(a) NYMEX natural gas prices have been updated for actual contract prices through November 2009 and NYMEX oil prices have been updated for actual contract prices through September 2009.

(b) Production tax per mcfe is based on NYMEX prices of $57.75 per bbl of oil and $4.75 to $6.25 per mcf of natural gas during 2009 and $80.00 per bbl of oil and $7.00 to $8.25 per mcf of natural gas during 2010 and 2011.

(c) Excludes expenses associated with noncash stock compensation.

(d) Does not include gains or losses on interest rate derivatives (ASC 815).

(e) 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.

(f) Assumes NYMEX natural gas prices of $5.00 to $6.00 per mcf and NYMEX oil prices of $57.75 per bbl in 2009, NYMEX natural gas prices of $6.50 to $7.50 per mcf and NYMEX oil prices of $80.00 per bbl in 2010 and NYMEX natural gas prices of $ 7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 per bbl in 2011.

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) For swap instruments, Chesapeake receives a fixed price for the commodity and pays a floating market price to the counterparty.
2) Collars 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 call and the put strike price, no payments are due from either party.
3) For 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) For written 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 Chesapeake.
5) Basis protection swaps 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,

6) 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.
A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires Chesapeake to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.

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. Pursuant to ASC 815, 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. Following provisions of ASC 815, 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.

Excluding the swaps assumed in connection with the acquisition of CNR which are described below, 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
Q4 2009[(a)]	***107.2***	***$ 6.83***	***210***	***51***	%	***$*** 114.2	***$ 0.54***
Q1 2010	28.7	$ 9.84				$ 50.6	
Q2 2010	27.5	$ 8.83				$ 52.7	
Q3 2010	31.7	$ 9.60				$ 60.1	
Q4 2010	33.0	$ 9.77				$ 59.5	
Total	120.9	$ 9.53	892	14	%	$ 222.9	$ 0.25

2010[a]						
Total 2011[a]	23.7	$ 9.86	1,017	2 %	$ 62.7	$ 0.06

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at $6.00 covering 1 bcf for the remainder of 2009, $5.45 to $6.75 covering 70 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
Q4 2009[a]	52.1	$ 7.34	$ 8.88	***210***	***25 %***
Q1 2010	43.2	$ 6.49	$ 8.51		
Q2 2010	16.4	$ 7.04	$ 9.17		
Q3 2010	3.7	$ 7.60	$ 11.75		
Q4 2010	3.7	$ 7.60	$ 11.75		
Total 2010[a]	67.0	$ 6.75	$ 9.03	892	8 %
Total 2011	7.2	$ 7.70	$ 11.50	1,017	1 %

(a) Certain collar arrangements include three-way collars that include written put options with a strike price of $6.00 covering 11 bcf for the remainder of 2009 and ranging from $4.25 to $5.50 covering 26 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
Q4 2009	9.7	$ 6.51	$ 2.25	***210***	***5*** %
Q1 2010	69.3	$ 10.26	$ 0.61		
Q2 2010	74.6	$ 10.08	$ 0.56		
Q3 2010	75.4	$ 10.17	$ 0.56		
Q4 2010	75.4	$ 10.27	$ 0.56		
Total 2010	294.7	$ 10.19	$ 0.57	892	33 %
Total 2011	73.1	$ 10.25	$ 0.57	1,017	7 %

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

Non-Appalachia Appalachia

	Volume (Bcf)	NYMEX less[a]	Volume (Bcf)	NYMEX plus[a]
2009	***10.4***	***$ 1.64***	***4.4***	$ 0.27
2010	—	—	10.2	0.26
2011	45.1	0.82	12.1	0.25
2012	43.2	0.85	—	—
Totals	***98.7***	$ 0.92	***26.7***	$ 0.26

(a) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with ASC 805, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($11 million as of September 30, 2009). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to ASC 815 *Derivatives and Hedging*, the assumed CNR derivative instruments are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows.

The following details the CNR derivatives (natural gas swaps) we have assumed:

	Open Swaps (Bcf)	Avg. NYMEX Strike Price Of Open Swaps	Avg. Fair Value Upon Acquisition of Open Swaps	Initial Liability Acquired	Assuming Natural Gas Production (Bcf)	Open Swap Positions as a % of Estimated Total Natural Gas Production
Q4 2009	4.6	$ 5.18	$ 7.32	$ (2.14)	***210***	2 %

Note: Not shown above are collars covering 1 bcf of production for the remainder of 2009 at an average floor and ceiling of $4.50 and $6.00.

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 Gains (Losses) from Lifted Trades	Total Lifted Gains (Losses) per bbl of Estimated Total Oil

				Total Oil Production	($ millions)	Production
Q4 2009	1,058	$ 87.05	***2,947***	***36 %***	**$** 9.4	***$ 3.20***
Q1 2010	1,170	$ 90.25	—	—	$ (4.0)	—
Q2 2010	1,183	$ 90.25	—	—	$ (4.0)	—
Q3 2010	1,196	$ 90.25	—	—	$ (4.2)	—
Q4 2010	1,196	$ 90.25	—	—	$ (4.2)	—
Total 2010[(a)]	4,745	$ 90.25	12,500	38 %	$ (16.4)	$ (1.31)
Total 2011[(a)]	1,095	$ 104.75	13,000	8 %	$ 32.8	$ 2.53

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $50.00 to $60.00 covering 1 mmbbls for the remainder of 2009 and $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 for the remainder of 2009 at a weighted average price of $112.50 per bbl for a weighted average discount of $1.21 per bbl, 3 mmbbls of oil production in 2010 at a weighted average price of $115.00 per bbl for a weighted average discount of $0.86 per bbl and 4 mmbls of oil production in 2011 at a weighted average price of $105.00 per bbl for a weighted average premium of $4.27 per bbl.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF OCTOBER 13, 2009
(PROVIDED FOR REFERENCE ONLY)
NOW SUPERSEDED BY OUTLOOK AS OF NOVEMBER 2, 2009

Years Ending December 31, 2009, 2010 and 2011

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of October 13, 2009, we are using the following key assumptions in our projections for 2009, 2010 and 2011.

The primary changes from our August 3, 2009 Outlook are in ***italicized bold*** and are explained as follows:

4) Our first projections for full-year 2011 have been provided;

5) Our production guidance has been updated;

6) Projected effects of changes in our hedging positions have been updated;

7) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been updated;

8) Our projections have been adjusted to reflect the anticipated deconsolidation as of January 1, 2010 of Chesapeake's 50/50 midstream joint venture with Global Infrastructure Partners;

9) Our cash inflows from property sales and capital spending have been updated to reflect our second amendment to our Haynesville Shale joint venture with Plains Exploration & Production Company;

10) Our asset monetization projections have been updated; and

11) Certain revenue, cost and cash income tax assumptions have been updated.

	Year Ending 12/31/2009	**Year Ending 12/31/2010**	**Year Ending 12/31/2011**
Estimated Production:			
Natural gas – bcf	***815 – 825***	***882 – 902***	***1,007 – 1,027***
Oil – mbbls	12,000	***12,500***	***13,000***
Natural gas equivalent – bcfe	***885 – 895***	***957 – 977***	***1,085 – 1,105***
Daily natural gas equivalent midpoint – mmcfe	***2,440***	***2,650***	***3,000***
Year-over-year estimated production increase	***5 – 6%***	***8 – 10%***	***12 – 14%***
Year-over-year estimated production increase excluding divestitures and curtailments	***9 – 10%***	***10 – 12%***	***13 – 15%***
NYMEX Prices [(a)] (for calculation of realized hedging effects only):			
Natural gas - $/mcf	***$3.85***	***$7.00***	***$7.50***
Oil - $/bbl	***$57.75***	***$80.00***	***$80.00***
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	***$3.00***	***$0.85***	***$0.22***
Oil - $/bbl	***$3.77***	***$1.99***	***$5.71***
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	20 – 30%	***15 – 25%***	***15 – 25%***
Oil - $/bbl	7 – 10%	***7 – 10%***	***7 – 10%***
Operating Costs per Mcfe of Projected Production:			
Production expense	$1.10 – 1.20	***$0.90 – 1.10***	***$0.90 – 1.10***
Production taxes (~ 5% of O&G revenues)[(b)]	$0.20 – 0.25	$0.30 – 0.35	***$0.30 – 0.35***
General and administrative[(c)]	$0.33 – 0.37	$0.33 – 0.37	***$0.33 – 0.37***
Stock-based compensation (non-cash)	$0.10 – 0.12	$0.10 – 0.12	***$0.10 – 0.12***
DD&A of natural gas and oil assets	$1.50 – 1.70	$1.50 – 1.70	***$1.50 – 1.70***
Depreciation of other assets	$0.25 – 0.30	***$0.20 – 0.25***	***$0.20 – 0.25***
Interest expense[(d)]	$0.30 – 0.35	$0.35 – 0.40	***$0.35 – 0.40***
Other Income per Mcfe:			
Marketing, gathering and compression net margin	$0.10 – 0.12	***$0.07 – 0.09***	***$0. 07 – 0.09***
Service operations net margin	$0.04 – 0.06	$0.04 – 0.06	***$0.04 – 0.06***
Equity in income of CMP	–	***$0.04 – 0.06***	***$0.04 – 0.06***
Book Tax Rate (all deferred)	37.5%	39%	***39%***

Equivalent Shares Outstanding (in millions):			
Basic	610 – 615	625 – 630	***635 –640***
Diluted	625 – 630	640 – 645	***645 – 650***
Cash Flow Projections ($ in millions):			
Net Cash Inflows:			
Operating cash flow before changes in assets and liabilities[e][f]	$3,700 – 3,750	***$4,350 – 5,050***	***$4,750 – 5,450***
Leasehold and producing property transactions:			
Sale of leasehold and producing properties	***$1,900 – 2,000***	***$1,500 – 2,000***	***$1,250 – 1,750***
Acquisition of leasehold and producing properties:	***($1,000 – 1,250)***	***($500 – 650)***	***($350 – 500)***
Net leasehold and producing property transactions	***$750 – 900***	***$1,000 – 1,350***	***$900 – 1,250***
Midstream equity financings and system sales	$600 – 800	$250 – 300	***$300 – 500***
Midstream credit facility draws (repayments)	($200 – 300)	$150 – 200	***–***
Proceeds from investments and other	$450	***–***	***$200 – 250***
Total Cash Inflows	***$5,300 – 5,600***	***$5,750 – 6,900***	***$6,150 – 7,450***
Net Cash Outflows:			
Drilling	***$3,150 – 3,350***	***$4,400 – 4,700***	***$4,600 – 4,900***
Geophysical costs	***$125 – 150***	***$125 – 150***	***$125 – 150***
Midstream infrastructure and compression	$700 – 900	$300 – 400	***$300 – 400***
Other PP&E	$400 – 450	$200 – 250	***$200 – 250***
Dividends, senior notes redemption, capitalized interest, etc.	$600 – 800	***$550 – 650***	***$450 – 550***
Cash income taxes	***$0 – 25***	***($100 – 200)***	***–***
Total Cash Outflows	$4,975 – 5,675	***$5,475 – 5,950***	***$5,675 – 6,250***
Net Cash Change	***($75) – 325***	***$275 – 950***	***$475 – 1,200***

At September 30, 2009, the company had $3.1 billion of cash and cash equivalents and additional borrowing capacity under its three revolving bank credit facilities.

(a) NYMEX natural gas prices have been updated for actual contract prices through October 2009 and NYMEX oil prices have been updated for actual contract prices through September 2009.

(b) Severance tax per mcfe is based on NYMEX prices of $57.75 per bbl of oil and $4.75 to $6.25 per mcf of natural gas during 2009 and $80.00 per bbl of oil and $7.00 to $8.25 per mcf of natural gas during 2010 and 2011.

(c) Excludes expenses associated with noncash stock compensation.

(d) Does not include gains or losses on interest rate derivatives (SFAS 133).

(e) 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.

(f) Assumes NYMEX natural gas prices of $5.00 to $6.00 per mcf and NYMEX oil prices of $57.75 per bbl in 2009, NYMEX natural gas prices of $6.50 to $7.50 per mcf and NYMEX oil prices of $80.00 per bbl in 2010 and NYMEX natural gas prices of $ 7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 per bbl in 2011.

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) For swap instruments, Chesapeake receives a fixed price for the commodity and pays a floating market price to the counterparty.
2) Collars 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 call and the put strike price, no payments are due from either party.
3) For 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) For written 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 Chesapeake.
5) Basis protection swaps are arrangements that guarantee a price differential to NYMEX for natural gas or oil from a specified delivery point. For Mid-Continent 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.
6) A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires Chesapeake to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.

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. Pursuant to SFAS 133, 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. Following provisions of SFAS 133, 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.

Excluding the swaps assumed in connection with the acquisition of CNR which are described below, 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
Q3 2009	***74.4***	***$ 7.32***			***$ 17.8***	
Q4 2009	***105.0***	***$ 6.88***			***$ 114.2***	
Q3-Q4 2009[(a)]	***179.4***	***$ 7.06***	***420***	***43***%	***$ 132.0***	***$ 0.31***
Q1 2010	***28.7***	***$ 9.84***			***$ 50.6***	
Q2 2010	***27.5***	***$ 8.83***			***$ 52.7***	
Q3 2010	***31.7***	***$ 9.60***			***$ 60.1***	
Q4 2010	***33.0***	***$ 9.77***			***$ 59.5***	
Total 2010[(a)]	***120.9***	***$ 9.53***	***892***	***14%***	***$ 222.8***	***$ 0.25***
Total 2011[(a)]	***23.7***	***$ 9.86***	***1,017***	***2%***	***$ 62.7***	***$ 0.06***

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at $6.00 covering 2 bcf in 2009,$5.45 to $6.75 covering 70 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
Q3 2009	102.7	$ 7.02	$ 8.76		
Q4 2009	52.1	$ 7.34	$ 8.88		
Q3-Q4 2009[(a)]	154.8	$ 7.12	$ 8.80	***420***	***37 %***
Q1 2010	***43.2***	***$ 6.49***	***$ 8.51***		
Q2 2010	***16.4***	***$ 7.04***	***$ 9.17***		
Q3 2010	***3.7***	***$ 7.60***	***$ 11.75***		
Q4 2010	***3.7***	***$ 7.60***	***$ 11.75***		
Total 2010[(a)]	***67.0***	***$ 6.75***	***$ 9.03***	***892***	8 %
Total 2011[(a)]	***7.2***	***$ 7.70***	***$ 11.50***	***1,017***	***1 %***

(a) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 36 bcf in 2009 and ranging from $4.25 to

$5.50 covering 26 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	
Q3 2009	14.0	$ 6.75	$ 1.61			
Q4 2009	***9.7***	***$ 6.51***	***$ 2.25***			
Q3-Q4 2009	***23.7***	***$ 6.65***	***$ 1.87***	***420***	***6***	%
Q1 2010	***69.3***	***$ 10.26***	***$ 0.61***			
Q2 2010	***74.6***	***$ 10.08***	***$ 0.56***			
Q3 2010	***75.4***	***$ 10.17***	***$ 0.56***			
Q4 2010	***75.4***	***$ 10.27***	***$ 0.56***			
Total 2010	***294.7***	$ 10.19	***$ 0.57***	***892***	***33***	***%***
Total 2011[(a)]	***73.1***	***$ 10.25***	***$ 0.57***	***1,017***	***7***	***%***

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

	Mid-Continent Volume (Bcf)	NYMEX less[(a)]	Appalachia Volume (Bcf)	NYMEX plus[(a)]
2009	10.9	$ 1.57	8.9	$ 0.27
2010	—	—	10.2	0.26
2011	45.1	0.82	12.1	0.25
2012	43.2	0.85	—	—
Totals	99.2	$ 0.92	31.2	$ 0.26

(a) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($19 million as of June 30, 2009). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities," the assumed CNR derivative instruments are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows.

The following details the CNR derivatives (natural gas swaps) we have assumed:

	Open Swaps (Bcf)	Avg. NYMEX Strike Price Of Open Swaps	Avg. Fair Value Upon Acquisition of Open Swaps	Initial Liability Acquired	Assuming Natural Gas Production (Bcf)	Open Swap Positions as a % of Estimated Total Natural Gas Production
Q3 2009	4.6	$ 5.18	$ 6.89	$ (1.71)		
Q4 2009	4.6	$ 5.18	$ 7.32	$ (2.14)		
Q3-Q4 2009	9.2	$ 5.18	$ 7.11	$ (1.92)	***420***	2 %

Note: Not shown above are collars covering 1.84 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00.

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
Q3 2009	1,058	$ 87.05			***$ 8.9***	
Q4 2009	1,058	$ 87.05			***$ 9.4***	
Q3-Q4 2009[(a)]	2,116	$ 87.05	5,974	35 %	***$ 18.3***	***$ 3.07***
Q1 2010	***1,170***	***$ 90.25***	***—***	***—***	***$ (4.0)***	***—***
Q2 2010	***1,183***	***$ 90.25***	***—***	***—***	***$ (4.0)***	***—***
Q3 2010	***1,196***	***$ 90.25***	***—***	***—***	***$ (4.2)***	***—***
Q4 2010	***1,196***	***$ 90.25***	***—***	***—***	***$ (4.2)***	***—***
Total 2010[(a)]	4,745	$ 90.25	***12,500***	***38 %***	***$ (16.4)***	***$ (1.31)***
Total 2011[(a)]	***1,095***	***$ 104.75***	***13,000***	***8 %***	***$ 32.8***	***$ 2.53***

(a) Certain hedging arrangements knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $50.00 to $60.00 covering 3 mmbbls in 2009 and $60.00 covering 5 mmbbls and 1 mmbbls in 2010 and 2011, respectively.

Note: Not shown above are written call options covering 2 mmbbls of oil production in 2009 at a weighted average price of $106.25 per bbl for a weighted average premium of $0.85 per bbl, 3 mmbbls of oil production in 2010 at a weighted average price of $115.00 per bbl for a weighted average premium of ($0.86) per bbl and 6 mmbls of oil production in 2011 at a weighted average price of $105.00 per bbl for a weighted average premium of $4.26 per bbl.

Source: Chesapeake Energy Corporation

Chesapeake Energy Corporation
Investor Contact:
Jeffrey L. Mobley, CFA, 405-767-4763
Senior Vice President –
Investor Relations and Research
jeff.mobley@chk.com
or
Media Contact:
Jim Gipson, 405-935-1310
Director – Media Relations
jim.gipson@chk.com
