NEWS RELEASE

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

Company Reports 2009 Second Quarter Adjusted Net Income to Common Shareholders of $377 Million, or $0.62 per Fully Diluted Common Share, on Revenue of $1.67 Billion; Net Income Available to Common Shareholders Was $237 Million, or $0.39 per Fully Diluted Common Share Company Reports 2009 Second Quarter Production of 2.453 Bcfe per Day, an Increase of 4% over 2009 First Quarter Production and 5% over 2008 Second Quarter Production Company Increases Proved Reserves by 0.7 Tcfe to 12.5 Tcfe and Delivers 2009 Second Quarter Drilling and Net Acquisition Costs of $0.72 per Mcfe; Company Record Set for Organic Reserve Additions and Reserve Replacement During a Six-Month Period Company Provides Update on 2009 Asset Monetization Initiatives and Hedging Positions

OKLAHOMA CITY--(BUSINESS WIRE)--Aug. 3, 2009-- Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operating results for the 2009 second quarter. For the quarter, Chesapeake reported net income to common shareholders of $237 million ($0.39 per fully diluted common share), operating cash flow of $1.006 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $763 million (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.673 billion and production of 223 billion cubic feet of natural gas equivalent (bcfe).

The company's 2009 second quarter results include a realized natural gas and oil hedging gain of $597 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 second quarter of $377 million ($0.62 per fully diluted common share) and adjusted ebitda of $1.030 billion. The excluded items and their effects on 2009 second quarter reported results are detailed as follows:

- a net unrealized noncash after-tax mark-to-market loss of $109 million resulting from the company's natural gas, oil and interest rate hedging programs;
- an after-tax charge of $21 million related to restructuring and relocation costs in the company's Eastern Division and certain other work force reduction costs; and
- a combined after-tax charge of $10 million related to estimated bad debts owed to Chesapeake that may be uncollectible, the impairment of an investment 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 second quarter and compares them to results during the 2008 first quarter and the 2008 second quarter.

	Three Months Ended		
	6/30/09	**3/31/09**	6/30/08[(a)]
Average daily production (in mmcfe)	2,453	2,367	2,328
Natural gas as % of total production	92	92	92
Natural gas production (in bcf)	204.3	195.7	195.0
Average realized natural gas price ($/mcf) [(b)]	5.56	6.05	8.18
Oil production (in mbbls)	3,152	2,874	2,816
Average realized oil price ($/bbl) [(b)]	56.72	39.12	76.96
Natural gas equivalent production (in bcfe)	223.2	213.0	211.9
Natural gas equivalent realized price ($/mcfe) [(b)]	5.89	6.09	8.55
Natural gas and oil marketing income ($/mcfe)	.14	.14	.12
Service operations income (loss) ($/mcfe)	(.01)	.03	.04
Production expenses ($/mcfe)	(.95)	(1.12)	(1.03)
Production taxes ($/mcfe)	(.11)	(.11)	(.41)
General and administrative costs ($/mcfe) [(c)]	(.25)	(.33)	(.38)
Stock-based compensation ($/mcfe)	(.09)	(.09)	(.10)
DD&A of natural gas and oil properties ($/mcfe)	(1.32)	(2.10)	(2.47)
D&A of other assets ($/mcfe)	(.26)	(.27)	(.19)
Interest expense ($/mcfe) [(b)]	(.29)	(.14)	(.32)
Operating cash flow ($ in millions) [(d)]	1,006	999	1,468
Operating cash flow ($/mcfe)	4.51	4.69	6.93
Adjusted ebitda ($ in millions) [(e)]	1,030	988	1,435
Adjusted ebitda ($/mcfe)	4.62	4.64	6.77
Net income (loss) to common shareholders ($ in millions)	237	(5,746)	(1,643)
Earnings (loss) per share – assuming dilution ($)	.39	(9.63)	(3.16)
Adjusted net income to common shareholders ($ in millions) [(f)]	377	277	485
Adjusted earnings per share – assuming dilution ($)	.62	.46	.90

(a) reflects the adoption and retrospective application of FSP APB 14-1 "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion"

(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 (loss) 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 (loss) available to common shareholders, as adjusted to remove the effects of certain items detailed on page 17

2009 Second Quarter Average Daily Production Increases 4% over 2009 First Quarter Production and 5% over 2008 Second Quarter Production

As announced on July 30, 2009, the company's daily production for the 2009 second quarter averaged 2.453 bcfe, an increase of 86 million cubic feet of natural gas equivalent (mmcfe), or 4%, over the 2.367 bcfe produced per day in the 2009 first quarter and an increase of 125 mmcfe, or 5%, over the 2.328 bcfe produced per day in the 2008 second quarter. Adjusted for the company's 2009 voluntary production curtailments due to low natural gas and oil prices (which averaged approximately 74 mmcfe per day during the 2009 second quarter), the company's three 2008 volumetric production payment sales (which averaged approximately 139 mmcfe per day during the 2009 second quarter) and the estimated impact from the company's 2008 sales of Woodford Shale and Fayetteville Shale properties (which would have averaged approximately 81 mmcfe per day during the 2009 second quarter), Chesapeake's sequential and year-over-year production growth rates would have been 4% and 16%, respectively, after making similar adjustments to prior quarters. The company is not currently curtailing production, but may do so again later this summer or fall as market conditions dictate. The company also expects that rising pipeline and gathering system pressures during the next few months will likely result in involuntary natural gas production curtailments across the industry.

Chesapeake's average daily production for the 2009 second quarter consisted of 2.245 billion cubic feet of natural gas (bcf) and 34,637 barrels of oil and natural gas liquids (bbls). The company's 2009 second quarter production of 223.2 bcfe was comprised of 204.3 bcf (92% on a natural gas equivalent basis) and 3.152 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis).

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2009 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $5.56 per thousand cubic feet (mcf) and $56.72 per bbl, for a realized natural gas equivalent price of $5.89 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas and oil hedging activities during the 2009 second quarter generated a $2.88 gain per mcf and a $3.13 gain per bbl for a 2009 second quarter realized hedging gain of $597 million, or $2.68 per mcfe. Without realized hedging gains, the company's average realized prices for the 2009 second quarter would have been $2.68 per mcf and $53.59 per bbl, for a natural gas equivalent price of $3.21 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2009 second quarter were a negative $0.83 per mcf and a negative $6.03 per bbl.

By comparison, average prices realized during the 2008 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.18 per mcf and $76.96 per bbl, for a realized natural gas equivalent price of $8.55 per mcfe. Realized losses from natural gas and oil hedging activities during the 2008 second quarter generated a $1.55 loss per mcf and a $42.85 loss per bbl for a 2008 second quarter realized hedging loss of $423 million, or $1.99 per mcfe. Without realized hedging gains, the company's average realized prices for the 2008 second quarter would have been $9.73 per mcf and $119.81 per bbl, for a natural gas equivalent price of $10.54 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2008 second quarter were a negative $1.21 per mcf and a negative $4.17 per bbl.

The following tables summarize Chesapeake's open hedge position through swaps and collars as of August 3, 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 August 3, 2009

	Natural Gas			**Oil**		
Year	**% Hedged**		**$ NYMEX**	**% Hedged**		**$ NYMEX**
3Q-4Q 2009 Total[(a)]	52	%	7.34	35	%	87.05

2010 Total[a]	13	%	9.78	40	%	90.25

Open Natural Gas Collar Positions as of August 3, 2009

Year	% Hedged		Average Floor $ NYMEX	Average Ceiling $ NYMEX
3Q-4Q 2009 Total[a]	38	%	7.12	8.80
2010 Total[a]	8	%	6.78	9.18

(a) Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $6.00 to $6.50 per mcf covering 5 bcf in 2009 and $5.45 to $6.75 per mcf covering 70 bcf in 2010, or approximately 63% of the company's natural gas swap positions in 2010. 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 36 bcf in 2009 and ranging from $4.25 to $6.00 per mcf covering 30 bcf in 2010, or approximately 23% and 42% of the company's natural gas collar positions in 2009 and 2010, respectively. Also, certain open oil swap positions include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $50 to $60 per bbl covering 3 mmbbls in 2009 and $60 per bbl covering 5 mmbbls in 2010, or virtually all of the company's oil swap positions in 2009 and 2010.

As of July 31, 2009, Chesapeake's natural gas and oil hedging positions with 14 different counterparties had a positive mark-to-market value of approximately $900 million.

The company's updated forecasts for 2009 and 2010 are attached to this release in an Outlook dated August 3, 2009, labeled as Schedule "A," which begins on page 20. This Outlook has been changed from the Outlook dated May 4, 2009, attached as Schedule "B," which begins on page 25, to reflect various updated information.

Company Increases Proved Natural Gas and Oil Reserves by 0.7 Tcfe to 12.5 Tcfe and Delivers 2009 Second Quarter Drilling and Net Acquisition Costs of $0.72 per Mcfe; Company Record Set for Organic Reserve Additions and Reserve Replacement During a Six-Month Period

Chesapeake began the 2009 second quarter with estimated proved reserves of 11.851 trillion cubic feet of natural gas equivalent (tcfe) and ended the 2009 second quarter with 12.525 tcfe, an increase of 674 bcfe, or 6%. During the 2009 second quarter, Chesapeake replaced 223 bcfe of production with an estimated 897 bcfe of new proved reserves for a reserve replacement rate of 402%. The quarter's reserve movement included 493 bcfe of extensions, 343 bcfe of positive performance revisions, 156 bcfe of positive revisions resulting from natural gas and oil price increases between March 31, 2009 and June 30, 2009 and 95 bcfe of net divestitures.

Chesapeake's total drilling and net acquisition costs for the 2009 second quarter were $0.72 per mcfe. This calculation excludes costs of $236 million for the acquisition of unproved properties and leasehold, $153 million for capitalized interest on unproved properties, and $26 million for seismic and asset retirement obligations, and also excludes positive revisions of proved reserves from higher natural gas and oil prices. Excluding these items and acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during the 2009 second quarter were $0.87 per mcfe, giving effect to the benefit of $311 million in drilling carries associated with the Haynesville ($118 million), Fayetteville ($166 million) and Marcellus ($27 million) joint ventures. A complete reconciliation of 2009 second quarter proved reserves and finding and acquisition costs is presented on page 11 of this release.

During the 2009 first half, Chesapeake increased its estimated proved reserves 474 bcfe, or 4%, from 12.051 tcfe at year-end 2008. For the 2009 first half, Chesapeake replaced 436 bcfe of production with an estimated 910 bcfe of new proved reserves for a reserve replacement rate of 209%. The reserve movement in the 2009 first half included 920 bcfe of extensions, 740 bcfe of positive performance revisions, 664 bcfe of downward revisions resulting from a decrease in natural gas prices between December 31, 2008 and June 30, 2009 and 86 bcfe of net divestitures. Chesapeake's 1,660 bcfe of extensions and performance revisions in the 2009 first half set a company record for the highest level of organic reserve additions during a six-month period and its organic reserve replacement rate of 381% for the six-month period was also the highest in the company's history.

Chesapeake's total drilling and net acquisition costs for the 2009 first half were $1.18 per mcfe. This calculation excludes costs of $746 million for the acquisition of unproved properties and leasehold, $314 million for capitalized interest on unproved properties, and $95 million for seismic and asset retirement obligations, and also excludes downward revisions of proved reserves from lower natural gas and oil prices. Excluding these items and acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during the 2009 first half were $1.15 per mcfe, giving effect to the benefit of $580 million in drilling carries associated with the Haynesville ($204 million), Fayetteville ($337 million) and Marcellus ($39 million) joint ventures. A complete reconciliation of 2009 first half 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 2009 first half, and drilled 580 gross operated wells (432 net wells with an average working interest of 74%) and participated in another 581 gross wells operated by other companies (44 net wells with an average working interest of 8%). The company's drilling success rate was 99% for both company-operated and non-operated wells. Also during the 2009 first half, Chesapeake invested $1.509 billion in operated wells (using an average of 104 operated rigs) and $401 million in non-operated wells (using an average of 53 non-operated rigs) for total drilling, completing and equipping costs of $1.910 billion (net of carries).

As of June 30, 2009, the present value of future net cash flows, discounted at 10% per year, of Chesapeake's estimated proved reserves (PV-10) was $11.076 billion using field differential adjusted prices based on NYMEX quarter-end prices of $3.89 per mcf and $70.00 per bbl. Chesapeake's PV-10 changes by approximately $400 million for every $0.10 per mcf change in natural gas prices and approximately $65 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 SFAS 69 standardized measure) using field differential adjusted prices based on NYMEX year-end prices of $5.71 per mcf and $44.61 per bbl. The June 30, 2008 PV-10 of the company's proved reserves was $51.5 billion using field differential adjusted prices based on NYMEX quarter-end prices of $13.10 per mcf and $140.02 per bbl.

The company calculates the standardized measure of future net cash flows in accordance with SFAS 69 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 $6.369 billion as of June 30, 2009, $5.822 billion as of December 31, 2008 and $4.585 billion as of June 30, 2008.

Company Updates Asset Monetization Plans

During 2009 and 2010, Chesapeake plans to increase its liquidity, reduce its borrowings under its revolving credit facility and also strengthen its balance sheet through asset monetizations and the growth of its proved reserve base. As part of this plan, Chesapeake is targeting to monetize leasehold, producing properties, midstream assets and other assets for a range of $2.35 to $3.05 billion in 2009 and $1.25 to $1.80 billion in 2010. The company anticipates utilizing the monetization proceeds for capital expenditures and to reduce borrowings under its revolving credit facility.

Since March 31, 2009, the company has sold or agreed to sell approximately $900 million of assets including producing properties and gathering assets located primarily in Louisiana for $208 million (closed June 30), certain midstream and real estate surface assets for $172 million (closed on various dates in the second quarter), producing properties in central Texas for $75 million (closed July 1), and certain other midstream assets in multiple transactions for a total of approximately $70 million (closings anticipated on various dates in the third quarter). In addition, the company today sold certain Chesapeake-operated long-lived producing assets in South Texas in its fifth volumetric production payment transaction (VPP) for proceeds of $371 million, or $5.46 per mcfe of proved reserves. The assets included proved reserves of approximately 68 bcfe and current net production of approximately 55 mmcfe per day.

Chesapeake is planning to sell certain non-Haynesville Shale producing assets in Louisiana in its sixth VPP in the next 90 days for approximately $225-$250 million and also other mature producing assets in the second half of 2009 for approximately $200 million. The company is also working to finalize agreements with a private equity investor to sell a 50% minority interest in its Barnett Shale and Mid-Continent natural gas gathering and processing assets in the company's midstream subsidiary, Chesapeake Midstream Partners. The company anticipates completing the midstream transaction in the 2009 third quarter for proceeds of more than $550 million. Finally, Chesapeake continues to have discussions with several companies about a possible joint venture on some or all of its Barnett Shale leasehold in a transaction targeted for completion by year-end 2009.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report our financial and operational results for the 2009 second quarter. Chesapeake was able to deliver very solid results for the quarter despite the 70% drop in natural gas prices over the past year as a result of our successful hedging program, strong operating capabilities, low cost structure, powerful assets and very attractive joint venture arrangements.

"We are particularly proud of our very strong quarterly proved reserve additions of 741 bcfe at a finding and net acquisition cost of $0.72 per mcfe and our outstanding organic reserve additions of 836 bcfe at a drilling cost of only $0.87 per mcfe. During the quarter, we benefited from $311 million of drilling carries and we anticipate receiving more than $3.7 billion of additional carries through 2013. We believe these carries, in combination with our very low-cost Big 4 shale and two major Granite Wash plays will result in very high returns on invested capital, reduced capital expenditures and a rapidly improving balance sheet for years to come.

"Our high level of hedging at attractive prices should continue to insulate Chesapeake from potentially soft natural gas prices during the remainder of 2009. We believe that dramatically reduced U.S. drilling activity should soon lead to steep natural gas production declines in the industry. This should work to tighten natural gas markets, lift natural gas prices and improve the company's profitability in 2010 and beyond.

"Chesapeake's 2009 asset monetization program is on track with $900 million of proceeds captured to date and multiple transactions progressing toward completion in the second half of 2009 that will lead to total asset monetizations for the year of between $2.35 and $3.05 billion. We anticipate this program, combined with strong operating cash flow, will enable the company to continue funding its highly economic investment program solely from internal resources while at the same time reducing the company's debt levels both absolutely and on a per proved mcfe basis. We believe Chesapeake is very well positioned to deliver substantial quarterly increases in value to our investors in the years ahead."

Conference Call Information

A conference call to discuss this release has been scheduled for Tuesday morning, August 4, 2009, at 9:00 a.m. EDT. The telephone number to access the conference call is **913-981-5574** or toll-free **888-596-2560**. The passcode for the call is **3824854**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 9:00 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from 1:00 p.m. EDT on August 4, 2009 through midnight EDT on August 18, 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 **3824854**. 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 Item 1A of our 2008 Annual Report on Form 10-K we filed with the U.S. Securities and Exchange Commission on March 2, 2009. 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 financial crisis 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 legislative and regulatory changes such as those proposed with respect to commodity derivatives trading, natural gas and oil tax incentives and deductions, hydraulic fracturing and climate change; 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 largest independent producer 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

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(unaudited)

THREE MONTHS ENDED:	**June 30, 2009**		**June 30,** 2008[(a)]	
	$	**$/mcfe**	**$**	**$/mcfe**
REVENUES:				
Natural gas and oil sales	1,097	4.92	(1,594)	(7.53)
Natural gas and oil marketing sales	532	2.38	1,099	5.19
Service operations revenue	44	0.20	40	0.19
Total Revenues	1,673	7.50	(455)	(2.15)
OPERATING COSTS:				
Production expenses	213	0.95	219	1.03
Production taxes	24	0.11	88	0.41
General and administrative expenses	74	0.33	101	0.48

Natural gas and oil marketing expenses	500	2.24	1,075	5.08
Service operations expense	46	0.21	32	0.15
Natural gas and oil depreciation, depletion and amortization	295	1.32	523	2.47
Depreciation and amortization of other assets	58	0.26	40	0.19
Impairment of other assets	5	0.02	—	—
Restructuring costs	34	0.16	—	—
Total Operating Costs	1,249	5.60	2,078	9.81
INCOME (LOSS) FROM OPERATIONS	424	1.90	(2,533)	(11.96)
OTHER INCOME (EXPENSE):				
Other income (expense)	(2)	(0.01)	(1)	(0.01)
Interest expense	(22)	(0.10)	(54)	(0.25)
Impairment of investments	(10)	(0.04)	—	—
Loss on exchanges of Chesapeake debt	(2)	(0.01)	—	—
Total Other Income (Expense)	(36)	(0.16)	(55)	(0.26)
INCOME (LOSS) BEFORE INCOME TAXES	388	1.74	(2,588)	(12.22)
Income Tax Expense (Benefit):				
Current	1	—	3	0.01
Deferred	144	0.65	(999)	(4.71)
Total Income Tax Expense (Benefit)	145	0.65	(996)	(4.70)
NET INCOME (LOSS)	243	1.09	(1,592)	(7.52)
Preferred stock dividends	(6)	(0.03)	(9)	(0.04)
Loss on conversion/exchange of preferred stock	—	—	(42)	(0.20)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	237	1.06	(1,643)	(7.76)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.39		$ (3.16)	
Assuming dilution	$ 0.39		$ (3.16)	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	603		521	
Assuming dilution	610		521	

(a) Adjusted for the retrospective application of FSP APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion.”

CHESAPEAKE ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(unaudited)

SIX MONTHS ENDED:	**June 30, 2009**		**June 30, 2008**[a]	
	$	**$/mcfe**	**$**	**$/mcfe**

REVENUES:				
Natural gas and oil sales	2,494	5.72	(821)	(1.97)
Natural gas and oil marketing sales	1,084	2.49	1,895	4.55
Service operations revenue	90	0.20	82	0.20
Total Revenues	3,668	8.41	1,156	2.78
OPERATING COSTS:				
Production expenses	451	1.03	419	1.01
Production taxes	46	0.11	163	0.39
General and administrative expenses	164	0.38	180	0.44
Natural gas and oil marketing expenses	1,023	2.35	1,849	4.44
Service operations expense	87	0.20	67	0.16
Natural gas and oil depreciation, depletion and amortization	742	1.70	1,038	2.49
Depreciation and amortization of other assets	115	0.26	76	0.18
Impairment of natural gas and oil properties and other assets	9,635	22.08	—	—
Restructuring costs	34	0.08	—	—
Total Operating Costs	12,297	28.19	3,792	9.11
INCOME (LOSS) FROM OPERATIONS	(8,629)	(19.78)	(2,636)	(6.33)
OTHER INCOME (EXPENSE):				
Other income (expense)	5	0.01	(11)	(0.03)
Interest expense	(8)	(0.02)	(153)	(0.37)
Impairment of investments	(162)	(0.37)	—	—
Loss on exchanges of Chesapeake debt	(2)	—	—	—
Total Other Income (Expense)	(167)	(0.38)	(164)	(0.40)
INCOME (LOSS) BEFORE INCOME TAXES	(8,796)	(20.16)	(2,800)	(6.73)
Income Tax Expense (Benefit):				
Current	1	—	3	0.01
Deferred	(3,299)	(7.56)	(1,081)	(2.60)
Total Income Tax Expense (Benefit)	(3,298)	(7.56)	(1,078)	(2.59)
NET INCOME (LOSS)	(5,498)	(12.60)	(1,722)	(4.14)
Preferred stock dividends	(12)	(0.03)	(21)	(0.05)
Loss on conversion/exchange of preferred stock	—	—	(42)	(0.10)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	(5,510)	(12.63)	(1,785)	(4.29)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$(9.18)		$(3.52)	
Assuming dilution	$(9.18)		$(3.52)	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	600		507	
Assuming dilution	600		507	

(a) Adjusted for the retrospective application of FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion."

CHESAPEAKE ENERGY CORPORATION

CHESAPEAKE ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

($ in millions)

(unaudited)

	June 30, 2009	December 31, 2008 [a]
Cash and cash equivalents	$ 554	$ 1,749
Other current assets	2,394	2,543
Total Current Assets	2,948	4,292
Property and equipment (net)	26,736	33,308
Other assets	785	993
Total Assets	$ 30,469	$ 38,593
Current liabilities	$ 2,974	$ 3,621
Long-term debt, net [b]	13,568	13,175
Asset retirement obligation	279	269
Other long-term liabilities	740	311
Deferred tax liability	906	4,200
Total Liabilities	18,467	21,576
Stockholders' Equity	12,002	17,017
Total Liabilities & Stockholders' Equity	$ 30,469	$ 38,593
Common Shares Outstanding (in millions)	630	607

CHESAPEAKE ENERGY CORPORATION

CAPITALIZATION

($ in millions)

(unaudited)

	June 30, 2009	% of Total Book Capitalization		December 31, 2008[a]	% of Total Book Capitalization	
Total debt, net cash [b]	$ 13,014	52	%	$ 11,426	40	%
Stockholders' equity	12,002	48	%	17,017	60	%
Total	$ 25,016	100	%	$ 28,443	100	%

(a) Adjusted for the retrospective application of FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion."

(b) Includes $3.131 billion of borrowings under both the company's $3.5 billion revolving bank credit facility and the company's $460 million midstream revolving bank credit facility. At June 30, 2009, the company had $792 million of additional borrowing capacity under these two 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 JUNE 30, 2009	Cost	Reserves (in bcfe)	$/mcfe
Exploration and development costs	$ 724	836 (a)	0.87
Acquisition of proved properties	—	4	—
Divestitures of proved properties	(193)	(99)	1.96
Other	2 (b)	—	—
Drilling and net acquisition cost	533	741	0.72
Revisions – price	—	156	—
Acquisition of unproved properties and leasehold	236	—	—
Capitalized interest	153 (c)	—	—
Geological and geophysical costs	30	—	—
Leasehold, capitalized interest, geological and geophysical	419	—	—
Subtotal	952	897	1.06
Asset retirement obligation and other	(4)	—	—
Total	$ 948	897	1.06

(a) Includes 343 bcfe of performance revisions (247 bcfe relating to infill drilling and increased density locations and 96 bcfe of other performance related revisions) and excludes upward revisions of 156 bcfe resulting from natural gas and oil price increases between March 31, 2009 and June 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 JUNE 30, 2009

(unaudited)

	Bcfe
Beginning balance, 04/01/09	11,851
Production	(223)
Acquisitions	4
Divestitures	(99)
Revisions – performance	343
Revisions – price	156
Extensions and discoveries	493
Ending balance, 06/30/09	12,525
Reserve replacement	897
Reserve replacement ratio [(a)]	402 %

(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)

SIX MONTHS ENDED JUNE 30, 2009	Cost	Reserves (in bcfe)	$/mcfe
Exploration and development costs	$ 1,910	1,660 (a)	1.15
Acquisition of proved properties	17	13	1.30
Divestitures of proved properties	(193)	(99)	1.96
Other	118 (b)	—	—
Drilling and net acquisition cost	1,852	1,574	1.18
Revisions – price	—	(664)	—
Acquisition of unproved properties and leasehold	746	—	—
Capitalized interest	314 (c)	—	—
Geological and geophysical costs	97	—	—
Leasehold, capitalized interest, geological and geophysical	1,157	—	—
Subtotal	3,009	910	3.30
Asset retirement obligation and other	(2)	—	—
Total	$ 3,007	910	3.30

(a) Includes 740 bcfe of performance revisions (564 bcfe relating to infill drilling and increased density locations and 176 bcfe of other performance related revisions) and excludes downward revisions of 664 bcfe resulting from natural gas and oil price declines between December 31, 2008 and June 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

SIX MONTHS ENDED JUNE 30, 2009

(unaudited)

	Bcfe
Beginning balance, 01/01/09	12,051
Production	(436)
Acquisitions	13
Divestitures	(99)
Revisions – performance	740
Revisions – price	(664)
Extensions and discoveries	920
Ending balance, 06/30/09	12,525

Reserve replacement	910	
Reserve replacement ratio [(a)]	209	%

(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 June 30,		SIX MONTHS ENDED June 30,	
	2009	**2008**	**2009**	**2008**
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 548	$ 1,896	$ 1,223	$ 3,329
Natural gas derivatives – realized gains (losses)	587	(302)	1,096	(34)
Natural gas derivatives – unrealized losses	(192)	(2,526)	(123)	(3,528)
Total Natural Gas Sales	943	(932)	2,196	(233)
Oil sales	169	337	272	596
Oil derivatives – realized gains (losses)	10	(121)	19	(174)
Oil derivatives – unrealized gains (losses)	(25)	(878)	7	(1,010)
Total Oil Sales	154	(662)	298	(588)
Total Natural Gas and Oil Sales	$ 1,097	$ (1,594)	$ 2,494	$ (821)
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 2.68	$ 9.73	$ 3.06	$ 8.70
Oil ($ per bbl)	$ 53.59	$ 119.81	$ 45.19	$ 107.13
Natural gas equivalent ($ per mcfe)	$ 3.21	$ 10.54	$ 3.43	$ 9.43
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 5.56	$ 8.18	$ 5.80	$ 8.61
Oil ($ per bbl)	$ 56.72	$ 76.96	$ 48.32	$ 75.86
Natural gas equivalent ($ per mcfe)	$ 5.89	$ 8.55	$ 5.98	$ 8.93
Interest Expense (Income) ($ in millions):				
Interest	$ 69	$ 72	$ 107	$ 158
Derivatives – realized gains	(5)	(4)	(12)	(4)
Derivatives – unrealized gains	(42)	(14)	(87)	(1)
Total Interest Expense	$ 22	$ 54	$ 8	$ 153

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	June 30, 2009	June 30, 2008 [(a)]
Beginning cash	$ 83	$ 1
Cash provided by operating activities	$ 737	$ 1,283
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	$ (745)	$ (1,529)
Acquisitions proved and unproved properties and leasehold	(160)	(1,917)
Divestitures of proved and unproved properties and leasehold and VPPs	228	620
Additions to other property and equipment	(313)	(678)
Capitalized interest on unproved properties	(153)	(121)
Other	45	(56)
Total cash used in investing activities	$ (1,098)	$ (3,681)
Cash provided by financing activities	$ 832	$ 2,397
Ending cash	$ 554	$ —

SIX MONTHS ENDED:	June 30, 2009	June 30, 2008 [(a)]
Beginning cash	$ 1,749	$ 1
Cash provided by operating activities	$ 1,998	$ 2,798
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	(2,092)	(2,935)
Acquisitions proved and unproved properties and leasehold	(412)	(2,835)
Divestitures of proved and unproved properties, leasehold and VPPs	228	863
Additions to other property and equipment	(980)	(1,229)
Capitalized interest on unproved properties	(314)	(224)
Other	105	(13)
Total cash used in investing activities	$ (3,465)	$ (6,373)
Cash provided by financing activities	$ 272	$ 3,574
Ending cash	$ 554	$ —

(a) 2008 data adjusted for the retrospective application of FSP APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion.”

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	June 30, 2009	March 31, 2009	June 30, 2008 [(a)]

CASH PROVIDED BY OPERATING ACTIVITIES	$ 737	$ 1,261	$ 1,283
Adjustments:			
Changes in assets and liabilities	269	(262)	185
OPERATING CASH FLOW [(b)]	$ 1,006	$ 999	$ 1,468

THREE MONTHS ENDED:	**June 30, 2009**	**March 31, 2009**	**June 30, 2008**[(a)]
NET INCOME (LOSS)	$ 243	$ (5,740)	$ (1,592)
Income tax expense (benefit)	145	(3,444)	(996)
Interest expense	22	(14)	54
Depreciation and amortization of other assets	58	57	40
Natural gas and oil depreciation, depletion and amortization	295	447	523
EBITDA [(c)]	$ 763	$ (8,694)	$ (1,971)

THREE MONTHS ENDED:	**June 30, 2009**	**March 31, 2009**	**June 30, 2008**[(a)]
CASH PROVIDED BY OPERATING ACTIVITIES	$ 737	$ 1,261	$ 1,283
Changes in assets and liabilities	269	(262)	185
Interest expense	22	(14)	54
Unrealized gains (losses) on natural gas and oil derivatives	(216)	101	(3,406)
Impairment of natural gas and oil properties and other assets	(5)	(9,630)	—
Impairment of investments	—	(153)	—
Restructuring costs	(29)	—	—
Other non-cash items	(15)	3	(87)
EBITDA [(c)]	$ 763	$ (8,694)	$ (1,971)

(a) Adjusted for the retrospective application of FSP APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion.”

(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)

SIX MONTHS ENDED:	June 30, 2009	June 30, 2008 [(a)]
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,998	$ 2,798
Adjustments:		
Changes in assets and liabilities	7	202
OPERATING CASH FLOW [(b)]	$ 2,005	$ 3,000

SIX MONTHS ENDED:	June 30, 2009	June 30, 2008 [(a)]
NET INCOME (LOSS)	$ (5,498)	$ (1,722)
Income tax expense (benefit)	(3,298)	(1,078)
Interest expense	8	153
Depreciation and amortization of other assets	115	76
Natural gas and oil depreciation, depletion and amortization	742	1,038
EBITDA [(c)]	$ (7,931)	$ (1,533)

SIX MONTHS ENDED:	June 30, 2009	June 30, 2008 [(a)]
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,998	$ 2,798
Changes in assets and liabilities	7	202
Interest expense	8	153
Unrealized gains (losses) on natural gas and oil derivatives	(116)	(4,538)
Impairment of natural gas and oil properties and other assets	(9,635)	—
Impairment of investments	(153)	—
Restructuring costs	(29)	—
Other non-cash items	(11)	(148)
EBITDA [(c)]	$ (7,931)	$ (1,533)

(a) Adjusted for the retrospective application of FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion."

(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:	**June 30, 2009**	**March 31, 2009**	**June 30, 2008 (a)**
Net income (loss) available to common shareholders	$ 237	(5,746)	$ (1,643)
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	109	(91)	2,086
Impairment of natural gas and oil properties and other assets, net of tax	3	6,019	—
Impairment of investments, net of tax	6	95	—
Restructuring costs, net of tax	21	—	—
Loss on exchanges of Chesapeake debt, net of tax	1	—	—
Loss on conversions or exchanges of preferred stock	—	—	42
Adjusted net income available to common shareholders (b)	377	277	485
Preferred stock dividends	6	6	9
Interest on 2.75% contingent convertible notes, net of tax	—	—	3
Total adjusted net income	$ 383	$ 283	$ 497
Weighted average fully diluted shares outstanding (c)	622	613	553
Adjusted earnings per share assuming dilution (b)	$ 0.62	$ 0.46	$ 0.90

(a) Adjusted for the retrospective application of FSP APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion.”

(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)

SIX MONTHS ENDED:	**June 30, 2009**	**June 30, 2008 (a)**
Net income (loss) available to common shareholders	$ (5,510)	$ (1,785)
Adjustments:		
Unrealized (gains) losses on derivatives, net of tax	19	2,790
Impairment of natural gas and oil properties and other assets, net of tax	6,022	—
Impairment of investments, net of tax	102	—
Restructuring cost, net of tax	21	—
Loss on exchanges of Chesapeake debt, net of tax	1	—
Loss on conversions or exchanges of preferred stock	—	42
Adjusted net income available to common shareholders (b)	655	1,047
Preferred stock dividends	12	21
Interest on 2.75% contingent convertible notes, net of tax	—	3
Total adjusted net income	$ 667	$ 1,071
Weighted average fully diluted shares outstanding (c)	618	541
Adjusted earnings per share assuming dilution (b)	$ 1.08	$ 1.98

(a) Adjusted for the retrospective application of FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion."

(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:	June 30, 2009	March 31, 2009	June 30, 2008 (a)
EBITDA	$ 763	$ (8,694)	$ (1,971)
Adjustments, before tax:			
Unrealized (gains) losses on natural gas and oil derivatives	216	(101)	3,406
Loss on exchanges of Chesapeake debt	2	—	
Impairment of natural gas and oil properties and other assets	5	9,630	—
Impairment of investments	10	153	—
Restructuring costs	34	—	—
Adjusted ebitda [b]	$ 1,030	$ 988	$ 1,435

(a) Adjusted for the retrospective application of FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion."

(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.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)

(unaudited)

SIX MONTHS ENDED:	June 30, 2009	June 30, 2008 (a)
EBITDA	$ (7,931)	$ (1,533)
Adjustments, before tax:		
Unrealized (gains) losses on natural gas and oil derivatives	116	4,538
Loss on exchanges of Chesapeake debt	2	—
Impairment of natural gas and oil properties and other assets	9,635	—
Impairment of investments	162	—
Restructuring costs	34	
Adjusted ebitda [b]	$ 2,018	$ 3,005

(a) Adjusted for the retrospective application of FSP APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion."

(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 AUGUST 3, 2009

Years Ending December 31, 2009 and 2010

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of August 3, 2009, we are using the following key assumptions in our projections for 2009 and 2010.

The primary changes from our May 4, 2009 Outlook are in ***italicized bold*** and are explained as follows:
1) Our production guidance has been updated. It reflects anticipated volumetric production payment transactions in 2009 and 2010 and does not assume any future voluntary production curtailments;
2) Projected effects of changes in our hedging positions have been updated;
3) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been updated for 2009 and 2010; and
4) Certain cost, book and cash income tax and share assumptions have been updated.

	Year Ending 12/31/2009		Year Ending 12/31/2010	
Estimated Production:				
Natural gas – bcf	***805 – 815***		***865 – 885***	
Oil – mbbls	12,000		12,000	
Natural gas equivalent – bcfe	***875 – 885***		***940 – 960***	
Daily natural gas equivalent midpoint – mmcfe	***2,410***		***2,600***	
Year-over-year estimated production increase	***4 – 5***	***%***	7 – 8	%
Year-over-year estimated production increase excluding divestitures and curtailments	***8 – 9***	***%***	9 – 10	%
NYMEX Prices [(a)] (for calculation of realized hedging effects only):				
Natural gas - $/mcf	***$4.30***		***$6.25***	
Oil - $/bbl	***$55.67***		$70.00	
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):				
Natural gas - $/mcf	***$2.68***		***$0.93***	
Oil - $/bbl	***$5.65***		$7.37	
Estimated Differentials to NYMEX Prices:				
Natural gas - $/mcf	20 – 30	%	15 – 20	%
Oil - $/bbl	7 – 10	%	5 – 7	%
Operating Costs per Mcfe of Projected Production:				
			$1.10 –	

Production expense	$1.10 – 1.20	1.20
Production taxes (~ 5% of O&G revenues)[b]	$0.20 – 0.25	$0.30 – 0.35
General and administrative[c]	$0.33 – 0.37	$0.33 – 0.37
Stock-based compensation (non-cash)	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	$1.50 – 1.70	$1.50 – 1.70
Depreciation of other assets	$0.25 – 0.30	$0.25 – 0.30
Interest expense[d]	$0.30 – 0.35	$0.35 – 0.40
Other Income per Mcfe:		
Natural gas and oil midstream income	$0.10 – 0.12	$0.09 – 0.11
Service operations income	$0.04 – 0.06	$0.04 – 0.06
Book Tax Rate (all deferred)	37.5 %	39 %
Equivalent Shares Outstanding (in millions):		
Basic	***610 – 615***	***625 – 630***
Diluted	***625 – 630***	***640 – 645***

Cash Flow Projections ($ in millions):

Net inflows:		
Operating cash flow before changes in assets and liabilities[e][f]	***$3,700 – 3,750***	***$3,950 – 4,650***
Leasehold and producing property transactions:		
Sale of leasehold and producing properties	***$1,750 – 2,250***	$1,000 – 1,500
Acquisition of leasehold and producing properties:	***($500 – 750)***	($350 – 500)
Net leasehold and producing property transactions	***$1,250 – 1,500***	$650 – 1,000
Midstream equity financings and system sales	***$600 – 800***	***$250 – 300***
Midstream credit facility draws (repayments)	***($200 – 300)***	***$150 – 200***
Proceeds from investments and other	$450	–
Total Cash Inflows	***$5,800 – 6,200***	***$5,000 – 6,150***
Net outflows:		
Drilling	***$3,000 – 3,200***	***$3,400 – 3,700***
Geophysical costs	$100 – 125	$100 – 125
Midstream infrastructure and compression	$700 – 900	$300 – 400
Other PP&E	$400 – 450	$200 – 250
Dividends, senior notes redemption, capitalized interest, etc.	$600 – 800	$600 – 700
Cash income taxes	$175 – 200	***($200 – 300)***

Total Cash Outflows	***$4,975 – 5,675***	***$4,400 – 4,875***
Net Cash Change	***$525 – 825***	***$600 – 1,275***

At June 30, 2009, the company had $1.3 billion of cash and cash equivalents and additional borrowing capacity under its two revolving bank credit facilities.

(a) NYMEX natural gas prices have been updated for actual contract prices through August 2009 and NYMEX oil prices have been updated for actual contract prices through June 2009.
(b) Severance tax per mcfe is based on NYMEX prices of $55.67 per bbl of oil and $5.00 to $6.00 per mcf of natural gas during 2009 and $70.00 per bbl of oil and $7.00 to $8.00 per mcf of natural gas during 2010.
(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 $60.00 per bbl in 2009 and NYMEX natural gas prices of $6.00 to $7.00 per mcf and NYMEX oil prices of $70.00 per bbl in 2010.

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	***75.4***	***$ 7.38***			$ 19.4	
Q4 2009	***126.7***	***$ 7.33***			$ 31.2	
Q3-Q4 2009(a)	***202.0***	***$ 7.35***	***410***	49 %	***$ 50.6***	***$ 0.12***
Total 2010(a)	110.2	***$ 9.78***	***875***	13 %	$ 224.6	$ 0.26

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at prices ranging from $6.00 to $6.50 covering 5 bcf in 2009 and $5.45 to $6.75 covering 70 bcf in 2010.

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***	***410***	***38***	***%***
Total 2010[a]	70.6	$ 6.78	$ 9.18	***875***	8	%

(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 $6.00 covering 30 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	***13.3***	***$ 6.78***	***$ 1.63***			
Q3-Q4 2009	***27.3***	***$ 6.76***	***$ 1.62***	***410***	***7***	***%***
Total 2010	298.5	$ 10.19	$ 0.58	***875***	***34***	***%***

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)***	***410***	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 Losses from Lifted Trades ($ millions)	Total Lifted Losses per bbl of Estimated Total Oil Production
Q3 2009	1,058	$ 87.05			$ (0.3)	
Q4 2009	1,058	$ 87.05			$ (0.4)	
Q3-Q4 2009[a]	2,116	$ 87.05	***5,974***	***35 %***	$ (0.7)	***$ (0.12)***
Total 2010[a]	4,745	$ 90.25	12,000	40 %	$ (6.9)	$ (0.58)

(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 in 2010.

Note: Not shown above are written call options covering 3 mmbbls of oil production in 2009 at a weighted average price of $101.79 per bbl for a weighted average premium of $0.64 per bbl and 5 mmbbls of oil production in 2010 at a weighted average price of $100.71 per bbl for a weighted average premium of $1.20 per bbl.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF MAY 4, 2009
(PROVIDED FOR REFERENCE ONLY)
NOW SUPERSEDED BY OUTLOOK AS OF AUGUST 3, 2009

Years Ending December 31, 2009 and 2010

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of May 4, 2009, we are using the following key assumptions in our projections for 2009 and 2010.

The primary changes from our February 17, 2009 Outlook are in ***italicized bold*** and are explained as follows:
1) Our production guidance has been updated to reflect estimated production curtailments starting in March 2009 and estimated to continue through June 2009 as well as anticipated volumetric production payment transactions in 2009 and in 2010;
2) Projected effects of changes in our hedging positions have been updated, particularly the restructuring of certain 2010 knockout swap positions;
3) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been reduced for 2009;
4) Certain cost, book and cash income tax rate and share assumptions have been updated; and
5) Our rate of DD&A for natural gas and oil assets has been reduced to reflect our 2009 first quarter impairment charge.

	Year Ending 12/31/2009		Year Ending 12/31/2010	
Estimated Production:				
Natural gas – bcf	***795 – 805***		***840 – 880***	
Oil – mbbls	12,000		12,000	
Natural gas equivalent – bcfe	***865 – 875***		***915 – 955***	
Daily natural gas equivalent midpoint – mmcfe	***2,380***		***2,560***	
Year-over-year estimated production increase	***3 – 4***	***%***	***7 – 8***	***%***
Year-over-year estimated production increase excluding divestitures and curtailments	***7 – 8***	***%***	***9 – 10***	***%***
NYMEX Prices [(a)] (for calculation of realized hedging effects only):				
Natural gas - $/mcf	***$4.93***		$7.00	
Oil - $/bbl	***$48.27***		$70.00	
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):				
Natural gas - $/mcf	***$2.29***		***$0.89***	
Oil - $/bbl	***$1.71***		***$7.37***	
Estimated Differentials to NYMEX Prices:				
Natural gas - $/mcf	***20 – 30***	***%***	15 – 20	%
Oil - $/bbl	***7 – 10***	***%***	5 – 7	%
Operating Costs per Mcfe of Projected Production:				
Production expense	$1.10 – 1.20		***$1.10 – 1.20***	
Production taxes (~ 5% of O&G revenues)[(b)]	***$0.20 – 0.25***		$0.30 – 0.35	
General and administrative[(c)]	$0.33 – 0.37		$0.33 – 0.37	
Stock-based compensation (non-cash)	$0.10 – 0.12		$0.10 – 0.12	
DD&A of natural gas and oil assets	***$1.50 – 1.70***		***$1.50 – 1.70***	
Depreciation of other assets	***$0.25 – 0.30***		***$0.25 – 0.30***	
Interest expense[(d)]	$0.30 – 0.35		$0.35 – 0.40	

Other Income per Mcfe:		
Natural gas and oil midstream income	***$0.10 – 0.12***	$0.09 – 0.11
Service operations income	$0.04 – 0.06	$0.04 – 0.06
Book Tax Rate (all deferred)	***37.5 %***	39 %
Equivalent Shares Outstanding (in millions):		
Basic	***605 – 610***	***615 – 620***
Diluted	***615 – 620***	***625 – 630***
Cash Flow Projections ($ in millions):		
Net inflows:		
Operating cash flow before changes in assets and liabilities[e][f]	***$3,600 – 3,650***	***$3,900 – 4,600***
Leasehold and producing property transactions:		
Sale of leasehold and producing properties	$1,500 – 2,000	$1,000 – 1,500
Acquisition of leasehold and producing properties:	***($450 – $600)***	($350 - $500)
Net leasehold and producing property transactions	***$1,050 – 1,400***	$650 – 1,000
Midstream financings	$500 – 600	$500 – 600
Proceeds from investments and other	***$450***	–
Total Cash Inflows	***$5,600 – 6,100***	***$5,050 – 6,200***
Net outflows:		
Drilling	***$2,700 – 2,900***	***$3,100 – 3,400***
Geophysical costs	$100 – 125	$100 – 125
Midstream infrastructure and compression	***$700 – 900***	***$300 – 400***
Other PP&E	***$400 – 450***	$200 – 250
Dividends, senior notes redemption, capitalized interest, etc.	$600 – 800	***$600 – 700***
Cash income taxes	$175 – 200	–
Total Cash Outflows	***$4,675 – 5,375***	***$4,300 – 4,875***
Net Cash Change	***$725 – 925***	***$750 – 1,325***

At March 31, 2009, the company had $1.7 billion of cash and cash equivalents and additional borrowing capacity under its two revolving bank credit facilities.

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

(b) Severance tax per mcfe is based on NYMEX prices of $48.27 per bbl of oil and $5.00 to $6.00 per mcf of natural gas during 2009 and $70.00 per bbl of oil and $7.00 to $8.00 per mcf of natural gas during 2010.

(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 $50.00 per bbl in 2009 and NYMEX natural gas prices of $6.00 to $7.00 per mcf and NYMEX oil prices of $70.00 per bbl in 2010.

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 and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
2) Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which 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 basis protection swaps, which 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.
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 predetermined knockout prices.
4) For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.
5) 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.
6) 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.
7) 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.

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
Q2 2009	***64.4***	***$ 7.70***				***$ 18.9***	
Q3 2009	***68.5***	***$ 7.83***				***$ 19.4***	
Q4 2009	***120.4***	***$ 7.57***				***$ 31.2***	
Q2-Q4 2009[(a)]	***253.3***	***$ 7.67***	***604***	***42***	***%***	***$ 69.5***	***$ 0.12***
Total 2010[(a)]	***121.2***	***$ 9.69***	***860***	***14***	***%***	***$ 224.6***	***$ 0.26***

(a) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty’s exposure at prices ranging from $6.00 to $6.50 covering 5 bcf in 2009 and $5.45 to $6.75 covering 70 bcf in 2010.

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	
Q2 2009	***97.8***	***$ 7.02***	***$ 8.83***			
Q3 2009	***102.7***	***$ 7.02***	***$ 8.76***			
Q4 2009	***52.1***	***$ 7.34***	***$ 8.88***			
Q2-Q4 2009[(a)]	***252.6***	***$ 7.08***	***$ 8.81***	***604***	***42***	***%***
Total 2010[(a)]	***70.6***	***$ 6.78***	***$ 9.18***	***860***	***8***	***%***

(a) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 62 bcf in 2009 and ranging from $4.25 to $6.00 covering 30 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
Q2 2009	***21.1***	***$ 7.64***	***$ 1.14***		

Q3 2009	***18.9***	***$ 7.53***	***$ 1.19***			
Q4 2009	***18.9***	***$ 7.58***	***$ 1.15***			
Q2-Q4 2009	***58.9***	***$ 7.59***	***$ 1.16***	***604***	***10***	***%***
Total 2010	***298.5***	***$ 10.19***	***$ 0.58***	***860***	***35***	***%***

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	***27.3***	***$ 1.46***	13.1	$ 0.28
2010	—	—	10.2	0.26
2011	45.1	0.82	12.1	0.25
2012	43.2	0.85	—	—
Totals	***115.6***	***$ 0.98***	35.4	$ 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 ($27 million as of March 31, 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
Q2 2009	4.6	$ 5.18	$ 6.87	$ (1.69)		
Q3 2009	4.6	$ 5.18	$ 6.89	$ (1.71)		
Q4 2009	4.6	$ 5.18	$ 7.32	$ (2.14)		
Q2-Q4 2009	13.8	$ 5.18	$ 7.28	$ (2.10)	***604***	2 %

Note: Not shown above are collars covering 2.75 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
Q2 2009	637	$ 77.38			***$ 4.4***	
Q3 2009	1,058	$ 87.05			***$ (0.3)***	
Q4 2009	1,058	$ 87.04			***$ (0.4)***	
Q2-Q4 2009[a]	2,753	$ 84.81	9,126	30 %	***$ 3.7***	***$ 0.41***
Total 2010[a]	4,745	$ 90.25	12,000	40 %	***$ (6.9)***	***$ (0.58)***

(a) Certain hedging arrangements include cap-swaps and 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 in 2010.

Note: Not shown above are written call options covering 3,850 mbbls of oil production in 2009 at a weighted average price of $101.79 per bbl for a weighted average premium of $0.64 per bbl and 5,110 mbbls of oil production in 2010 at a weighted average price of $100.71 per bbl for a weighted average premium of $1.20 per bbl.

Source: Chesapeake Energy Corporation

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