News Release

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CHESAPEAKE ENERGY CORPORATION UPDATES FINANCIAL AND OPERATIONAL PLANS THROUGH 2010

Chesapeake Announces Cash Neutral Budget and Plans to Build up to $4 Billion in Additional Cash Resources; Reduces Planned Capital Expenditures in 2009 and 2010; Production Growth Targets Lowered to 5-10% for 2009 and 10-15% for 2010

Company in Discussions to Sell Approximately 100 Bcfe of Proved Reserves for Proceeds of Approximately $450 Million, or $4.50 per Mcfe, in a Volumetric Production Payment Transaction

Chesapeake to Terminate Equity Distribution Program; Will Not Issue Shares under Prospectus Supplement Filed with the SEC

Company to Amend Acquisition Shelf Registration Statement on Form S-4; Common Shares to be Registered Will be Reduced from 50 Million to 25 Million

OKLAHOMA CITY, OK, DECEMBER 7, 2008 – Chesapeake Energy Corporation (NYSE:CHK) today announced updated financial and operational plans through 2010 in response to turbulent financial markets and increased uncertainty about the U.S. economy and natural gas and oil markets.

Chesapeake has further reduced its capital expenditure plans for 2009 and 2010 to achieve a cash neutral budget that does not depend on future asset sales. The company also plans to build up to $4 billion in additional cash resources in 2009 and 2010 through further asset monetizations.

From the budget presented in its November 3, 2008 Outlook, the company has decreased its drilling capital expenditure budget for 2009 and 2010 by a combined $2.9 billion, or 31%, and has also reduced its leasehold and producing property acquisition budget for

2009 and 2010 by a combined $2.2 billion, or 78%. In total, since July 31, 2008, Chesapeake has reduced its planned 2009 and 2010 drilling, leasehold and producing property acquisition budget by approximately $9.8 billion, or 58%, to approximately $7.2 billion.

Since August 2008, the company has steadily reduced its drilling and leasing activities in anticipation of a worsening U.S. economy, lower natural gas and oil prices and limited capital markets. The company is now utilizing approximately 130 operated rigs, down from a peak of 158 operated rigs in August 2008, and plans to further reduce its operated rig count to 110 to 115 rigs early in the 2009 first quarter. Chesapeake's costs in approximately 50% of these rigs will be fully or partially paid for by its third-party joint venture partners. Chesapeake anticipates its drilling carries will save the company approximately $1.2 billion of capital expenditures in 2009 and approximately $1.1 billion in 2010. The company will continue to monitor oil and natural gas markets and economic conditions and will further adjust its drilling and leasing activity levels if needed. Chesapeake is now anticipating production growth of approximately 5-10% in 2009 and 10-15% in 2010.

The company anticipates the combination of its joint venture drilling carries, 10-20% lower oilfield service costs and continued operational excellence will lead to very attractive drillbit finding costs and financial returns in 2009 and 2010. In its 2009 drilling program, for example, Chesapeake is targeting the addition of approximately 2.5 trillion cubic feet of natural gas equivalent (tcfe) of proved reserve additions from approximately $3.0 billion of net drilling capital expenditures, which would imply a production replacement rate of over 250% and a drillbit finding and development cost of approximately $1.20 per million cubic feet of natural gas equivalent (mcfe). Approximately 1.1 tcfe of the forecasted proved reserve additions are attributable to the company's interests in its three shale joint ventures and are based on approximately $500 million in drilling capital expenditures, net to Chesapeake, at a drillbit finding and development cost of approximately $0.45 per mcfe. Chesapeake is targeting to have proved reserves of 13.5 - 14.0 tcfe by year-end 2009, net of anticipated sales of proved reserves through volumetric production payments (VPPs).

To create additional value from its proved and unproved properties and to further enhance its financial liquidity, Chesapeake plans to continue selectively monetizing mature assets and undeveloped leasehold. Chesapeake is in discussions to sell certain Chesapeake-operated producing assets in the Anadarko and Arkoma Basins in its fourth VPP transaction. In this transaction, Chesapeake plans to sell producing assets with proved reserves of approximately 100 bcfe and current net production of approximately 55 mmcfe per day for proceeds of approximately $450 million, or $4.50 per mcfe. Chesapeake will retain future drilling rights on the properties. For accounting purposes, the transaction will be treated as a sale and the company's proved reserves and production will be reduced accordingly. The company anticipates completing this transaction by year-end 2008.

While Chesapeake received multiple bids for the purchase of its assets in South Texas, it believes the monetization of all or a portion of the producing assets though a VPP will be a more attractive transaction alternative. As a result, Chesapeake intends to market its fifth VPP transaction for a portion of its South Texas assets instead of selling the entire asset package. The company now anticipates selling producing assets in South Texas with proved reserves of approximately 80 bcfe and current net production of approximately 70 mmcfe per day for proceeds of approximately $450 million, or $5.60 per mcfe, and completing the transaction on these assets in the 2009 first quarter.

Additionally, the company continues to have discussions with multiple parties for either a minority investment in its midstream operations or the purchase of portion of its existing midstream assets. Chesapeake anticipates completing a midstream transaction, subject to reaching an agreement on acceptable terms, in the 2009 first quarter.

Over the past month, Chesapeake has also restructured its hedging position to provide further downside price protection. Chesapeake currently has approximately 76% of its anticipated 2009 natural gas production hedged through swaps and collars at an average swap and floor price of $8.20 per thousand cubic feet (mcf), including only 12% of its anticipated production hedged through swaps with knockout provisions, much of which is concentrated in the 2009 fourth quarter.

The company's updated forecasts for the 2008 fourth quarter and the full year 2009 and full year 2010 are attached to this release in an Outlook dated December 7, 2008, labeled as Schedule "A," which begins on page 6. This Outlook has been changed from the Outlook dated November 3, 2008 (attached as Schedule "B," which begins on page 11) to reflect various updated information.

Given the company's ample current and projected financial liquidity and in response to an unexpectedly negative market reaction to the company's November 26, 2008 filings with the Securities and Exchange Commission (SEC), Chesapeake plans to terminate the Distribution Agency Agreements it has with three securities firms and will not issue any shares under the equity distribution program described in its prospectus supplement dated November 26, 2008. Additionally, the company plans to amend its acquisition shelf registration statement filed on Form S-4 to reduce the number of common shares to be registered from 50 million to 25 million.

Management Comment

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to announce our cash neutral budget for 2009 and 2010 that does not depend on future asset sales. In addition, we plan to build up to $4 billion in additional cash resources over the next two years by continuing to monetize mature assets and undeveloped leasehold. The company has ample financial liquidity and we will monitor market conditions and proactively manage our capital spending levels in order to remain within our cash resources.

"Over the past year, we have captured significant value for our shareholders by monetizing a portion of our producing assets and undeveloped leasehold through VPPs and joint ventures. So far this year, we have received approximately $11.7 billion in cash and carried working interests through the sale of two VPPs, the creation of three joint ventures and the sale of our Arkoma Woodford Shale assets. Our cost basis in those assets was approximately $3.0 billion, creating a gain of approximately $8.7 billion. In addition, we still retain 80% of our Haynesville assets, 75% of our Fayetteville assets and 67.5% of our Marcellus assets with indicated combined values of more than $25 billion.

"We believe our approach of selectively monetizing mature assets and undeveloped leasehold is an attractive supplement to the traditional E&P industry business model of simply drilling wells and collecting proceeds from production over future years and decades. While that traditional activity will remain the foundation of our business, we believe Chesapeake's asset monetization activities increase our financial flexibility and create immediate value for shareholders with less risk. In time, we believe investors will more fully appreciate this aspect of our business as we successfully complete additional monetization transactions.

"The market response to our SEC fillings on November 26, 2008 was obviously very negative. We underestimated how the market would assess the purpose, implication, timing and magnitude of our filings. Our intent was to create broad financial flexibility for an uncertain economic and commodity market environment over the next few quarters. In retrospect, we made a mistake and we are terminating the Distribution Agency Agreements that permitted us to sell shares under a prospectus supplement and we are amending our acquisition shelf registration statement filed on Form S-4 to reduce the number of common shares registered from 50 million to 25 million.

"While the economy, stock market and natural gas and oil prices have made the second half of 2008 a brutal year for industry investors, Chesapeake has generated strong financial and operating results this year. We can not predict how the U.S. economy will perform in 2009 and 2010, but Chesapeake will continue executing its innovative, value-creating strategies and will continue building shareholder value in the years ahead, just as we have for the past 15 years as a public company."

Conference Call Information

A conference call to discuss this release has been scheduled for Monday morning, December 8, 2008, at 9:00 a.m. EST. The telephone number to access the conference call is **913-312-1236** or toll-free **888-211-7383**. The passcode for the call is **1193464**. 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 2:00 p.m. EST on December 8, 2008 through midnight EST on December 22, 2008. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **1193464**. The conference call will also be webcast live on 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 future natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned asset sales, budgeted capital expenditures for drilling and acquisitions of leasehold and producing property, and other anticipated cash outflows, 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 in "Risk Factors" in the Prospectus Supplement we filed with the U.S. Securities and Exchange Commission on November 26, 2008. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; unanticipated adverse effects the current financial crisis may have on our business and financial condition; the availability of capital on an economic basis, including through planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; our ability to compete effectively against strong independent natural gas and oil companies and majors; 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; uncertainties in evaluating natural gas and oil reserves of acquired properties and associated potential liabilities; possible unsuccessful exploration and development drilling; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; lower prices realized on natural gas and oil sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; the negative impact lower natural gas and oil prices could have on our ability to borrow; drilling and operating risks, including potential environmental liabilities; production interruptions that could adversely affect our cash flow; and 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 producer of natural gas in the U.S. Headquartered in Oklahoma City, the company's operations are focused on exploratory and developmental drilling and corporate and property acquisitions in the Fort Worth Barnett Shale, Fayetteville Shale, Haynesville Shale, Marcellus Shale, Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States. Further information is available at ***www.chk.com****.*

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF DECEMBER 7, 2008

Quarter Ending December 31, 2008 and Years Ending December 31, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of December 7, 2008, we are using the following key assumptions in our projections for the 2008 fourth quarter and the full years 2009 and 2010.

The primary changes from our November 3, 2008 Outlook are in ***italicized bold*** and are explained as follows:

1) Our assumptions for asset sale, financing and other cash inflows as well as capital expenditures and other cash outflows have been updated for the 2008 fourth quarter and full years 2009 and 2010;
2) Our natural gas production assumptions for the full years 2009 and 2010 have been reduced to reflect reduced drilling capital expenditures;
3) The projected effects of changes in our hedging positions have been updated;
4) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been reduced for the 2008 fourth quarter and full year 2009;
5) Certain cost and cash income tax assumptions have been updated; and
6) We have updated our average shares outstanding assumptions for the contingent convertible note exchanges completed during the 2008 fourth quarter.

	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production[a]			
Natural gas – bcf	188 – 192	***803 – 813***	***898 – 938***
Oil – mbbls	2,825	12,000	13,000
Natural gas equivalent – bcfe	205 – 209	***875 – 885***	***976 –1,016***
Daily natural gas equivalent midpoint – mmcfe	2,250	***2,410***	***2,730***
NYMEX Prices[b] (for calculation of realized hedging effects only):			
Natural gas - $/mcf	***$6.95***	***$7.00***	$8.00
Oil - $/bbl	***$63.91***	***$70.00***	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	***$2.06***	***$1.16***	***$0.95***
Oil - $/bbl	***$2.40***	***$7.08***	$4.79
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	10 – 14%	10 – 14%	10 – 14%
Oil - $/bbl	5 – 7%	5 – 7%	5 – 7%
Operating Costs per Mcfe of Projected Production:			
Production expense	$1.00 – 1.15	$1.10 – 1.20	$1.15 – 1.25
Production taxes[c]	$0.30 – 0.35	***$0.30 – 0.35***	$0.35 – 0.40
General and administrative[d]	$0.33 – 0.37	$0.33 – 0.37	$0.33 – 0.37
Stock-based compensation (non-cash)	$0.10 – 0.13	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	$2.25 – 2.30	$2.20 – 2.30	$2.15 – 2.25
Depreciation of other assets	$0.20 – 0.25	$0.20 – 0.24	$0.20 – 0.24
Interest expense[e]	$0.30 – 0.35	$0.40 – 0.45	$0.35 – 0.40
Other Income per Mcfe:			
Natural gas and oil marketing income	$0.09 – 0.11	$0.09 – 0.11	$0.09 – 0.11
Service operations income	$0.04 – 0.06	$0.04 – 0.06	$0.04 – 0.06
Book Tax Rate	38.5%	38.5%	38.5%
Equivalent Shares Outstanding – in millions:			
Basic	***573 – 578***	***588 – 593***	***598 – 603***
Diluted	***589 – 594***	***603 – 608***	***611 – 616***

Cash Flow Projections – in millions	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Net inflows:			
Operating cash flow before changes in assets and liabilities[f][g]	***$1,250 – 1,300***	***$4,800 – 5,100***	***$5,700-6,100***
Leasehold and producing property transactions:			
Sale of leasehold and producing properties[a]	***$1,400 – 1,450***	***$500 – 1,000***	***$500 – 1,000***
Sale of producing properties via VPP's[a]	***$425 – 475***	***$900 – 1,000***	***$450 – 500***
Acquisition of leasehold and producing properties	***($900 – 1,000)***	***($300 – 350)***	***($250 – 300)***
Net leasehold and producing property transactions	***$925 – 925***	***$1,100 – 1,650***	***$700 – 1,200***
Debt and equity offerings	**–**	–	–
Midstream financing and system sale or equity partner investment	***$460***	***$500 – 600***	***$500 – 600***
Proceeds from investments and other	**–**	**–**	**–**
Total Cash Inflows	***$2,635 – 2,685***	***$6,400 – 7,350***	***$6,900 – 7,900***
Net outflows:			
Drilling	***$1,400 – 1,500***	***$2,800 – 3,100***	***$3,500 – 3,800***
Geophysical costs	$75	***$100 – 125***	***$100 – 125***
Midstream infrastructure and compression	$300 – 325	***$500 – 600***	***$500 – 600***
Other PP&E	***$100 – 150***	***$200 – 250***	***$200 – 250***
Dividends, senior notes redemption, capitalized interest, etc.	$150 – 200	***$500 – 600***	***$500 – 600***
Cash income taxes	***$300 – 325***	***$250 – 275***	***$100 – 200***
Total Cash Outflows	***$2,325 – 2,575***	***$4,350 – 4,950***	***$4,900 – 5,575***
Net Cash Change	***$110 – 310***	***$2,050 – 2,400***	***$2,000 – 2,325***

(a) The 2008 fourth quarter production and cash flow forecasts reflect the completed Marcellus Shale joint venture with StatoilHydro, including $1.25 billion of cash received upon closing, the completed sale of undeveloped leasehold for approximately $200 million and the anticipated sale of producing properties for approximately $450 million in a volumetric production payment (VPP) transaction. The production and cash flow forecasts reflect anticipated sales by the company of producing properties in VPP transactions and/or leasehold for approximately $1.7 billion in 2009 and approximately $1.2 billion in 2010.

(b) NYMEX natural gas and oil prices have been updated for actual contract prices through December 2008 and October 2008, respectively.

(c) Severance tax per mcfe is based on approximately 5% of natural gas and oil revenues.

(d) Excludes expenses associated with noncash stock compensation.

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

(f) 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.

(g) Assumes NYMEX natural gas prices of $6.95 per mcf and NYMEX oil prices of $63.91 per bbl in the 2008 fourth quarter and NYMEX natural gas prices of $7.00 to $8.00 per mcf and NYMEX oil prices of $70.00 per bbl in 2009 and NYMEX natural gas prices of $7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 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:

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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

(v) 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.

(vi) 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.

(vii) 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 (losses) from lifted natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Gains (Losses) from Lifted Swaps ($ millions)	Total Lifted Gain (Loss) per Mcf of Estimated Total Natural Gas Production
Q4 2008	***103.7***	***$9.21***	190	***55%***	$85.2	$0.45
Total 2009[(1)]	***284.2***	***$9.21***	***808***	***35%***	($36.3)	($0.04)
Total 2010[(1)]	422.6	$9.58	***918***	***46%***	$33.9	$0.04

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.75 to $6.75 covering 93 bcf in 2009 and $5.45 to $7.40 covering 321 bcf in 2010.

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

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Collars as a % of Estimated Total Natural Gas Production
Q4 2008	26.6	$7.75	$9.32	190	14%
Total 2009[(1)]	***309.8***	***$7.36***	***$9.06***	***808***	***38%***
Total 2010[(1)]	25.6	$7.71	$11.46	***918***	***3%***

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 105 bcf in 2009 and at $6.00 covering 4 bcf in 2010.

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

	Call Options in Bcf's	Avg. NYMEX Call Price	Avg. Premium per mcf	Assuming Natural Gas Production in Bcf's of:	Call Options as a % of Estimated Total Natural Gas Production
Q4 2008	32.2	$10.37	$0.74	190	17%
Total 2009	216.2	$11.40	$0.63	***808***	***27%***
Total 2010	231.8	$10.77	$0.72	***918***	***25%***

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less*:	Volume in Bcf's	NYMEX plus*:
Q4 2008	32.1	$ 0.45	5.8	$ 0.33
2009	77.1	0.35	16.9	0.28
2010	—	—	10.2	0.26
2011	45.1	0.64	12.1	0.25
2012	43.2	0.48	—	—
Totals	197.5	$ 0.46	45.0	$ 0.27

* 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 ($76 million as of September 30, 2008). 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 in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
Q4 2008	9.7	$4.66	$7.84	($3.17)	190	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	***808***	2%

Note: Not shown above are collars covering 3.7 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 in mbbls	Avg. NYMEX Strike Price	Assuming Oil Production in mbbls of:	Open Swap Positions as a % of Estimated Total Oil Production	Total Gains (Losses) from Lifted Swaps ($ millions)	Total Lifted Gain (Loss) per bbl of Estimated Total Oil Production
Q4 2008(1)	1,214	$78.09	2,825	43%	($2.3)	($0.81)
Total 2009(1)	5,728	$81.19	12,000	48%	$38.5	$3.21
Total 2010(1)	4,745	$90.25	13,000	37%	—	—

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 982 mbbls in 2008, from $50.00 to $60.00 covering 6,038 mbbls in 2009 and $60.00 covering 4,745 mbbls in 2010.

Note: Not shown above are written call options covering 768 mbbls of production in 2008 at a weighted average price of $85.86 for a weighted average premium of $4.05, 5,110 mbbls of production in 2009 at a weighed average price of $133.93 for a weighted average premium of $3.90 and 5,110 mbbls of production in 2010 at a weighed average price of $140.00 for a weighted average premium of $4.46.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF NOVEMBER 3, 2008

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF DECEMBER 7, 2008

Quarter Ending December 31, 2008 and Years Ending December 31, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of November 3, 2008, we are using the following key assumptions in our projections for the fourth quarter of 2008 and the full years 2009 and 2010.

The sole change from our October 30, 2008 Outlook is the correction of our estimated 2009 operating cash flow to reflect changes in our hedging positions. The primary changes from our October 14, 2008 Outlook are in ***italicized bold*** and are explained as follows:

1) Natural gas production assumption for the quarter ending 12/31/08 has been reduced to reflect anticipated voluntary curtailments due to low wellhead price realizations;
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 reduced for the quarter ending 12/31/08; and
4) Certain cost and cash income tax assumptions have been updated.

	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production[a]			
Natural gas – bcf	***188 – 192***	893 – 913	1,032 – 1,072
Oil – mbbls	2,825	12,000	13,000
Natural gas equivalent – bcfe	***205 – 209***	965 – 985	1,110 –1,150
Daily natural gas equivalent midpoint – mmcfe	***2,250***	2,670	3,095
Year-over-year production increase	***1.4%***	***16.8%***	15.9%
NYMEX Prices (b) (for calculation of realized hedging effects only):			
Natural gas - $/mcf	***$7.00***	$8.00	$8.00
Oil - $/bbl	***$60.00***	$80.00	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	***$1.96***	***$0.70***	$0.82
Oil - $/bbl	***$5.48***	***$1.32***	$4.79
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	10 – 14%	10 – 14%	10 – 14%
Oil - $/bbl	5 – 7%	5 – 7%	5 – 7%
Operating Costs per Mcfe of Projected Production:			
Production expense	***$1.00 – 1.15***	$1.10 – 1.20	$1.15 – 1.25
Production taxes (~ 5% of O&G revenues) [c]	***$0.30 – 0.35***	$0.35 – 0.40	$0.35 – 0.40
General and administrative[d]	$0.33 – 0.37	$0.33 – 0.37	$0.33 – 0.37
Stock-based compensation (non-cash)	***$0.10 – 0.13***	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	***$2.25 – 2.30***	$2.20 – 2.30	$2.15 – 2.25
Depreciation of other assets	***$0.20 – 0.25***	$0.20 – 0.24	$0.20 – 0.24
Interest expense[e]	$0.30 – 0.35	$0.40 – 0.45	$0.35 – 0.40
Other Income per Mcfe:			
Natural gas and oil marketing income	$0.09 – 0.11	$0.09 – 0.11	$0.09 – 0.11
Service operations income	$0.04 – 0.06	$0.04 – 0.06	$0.04 – 0.06
Book Tax Rate	38.5%	38.5%	38.5%
Cash Income Taxes – in millions	***$550 – 650***	$200 – 300	$200 – 300
Equivalent Shares Outstanding – in millions:			
Basic	560 – 565	565 – 570	575 – 580
Diluted	580 – 585	585 – 590	595 – 600

Cash Flow Projections – in millions	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Net inflows:			
Operating cash flow before changes in assets and liabilities[f][g]	***$1,250 – 1,375***	***$5,350 – 5,700***	$6,250 – 6,750
Leasehold and producing property transactions:			
Sale of leasehold and producing properties[a]	$2,100 – 2,500	$1,250 – 2,000	$1,250 – 2,000
Sale of producing properties via VPP's[a]	$400 – 500	$1,000 – 1,250	$1,000 – 1,250
Acquisition of leasehold and producing properties	($750 - $1,000)	($1,250 - $1,750)	($1,000 - $1,500)
Net leasehold and producing property transactions	$1,750 – 2,000	$1,000 – 1,500	$1,250 – 1,750
Debt and equity offerings	–	–	–
Midstream financings	$1,050 – 1,275	$500 – 700	$500 – 700
Proceeds from investments and other	–	$500– 750	$150 – 250
Total Cash Inflows	***$4,050 – 4,650***	***$7,350 – 8,650***	$8,150 – 9,450
Net outflows:			
Drilling	$1,200 – 1,300	$4,250 – 4,750	$4,750 – 5,250
Geophysical costs	$75	$225 – 275	$225 – 275
Midstream infrastructure and compression	$300 – 325	$1,000 – 1,200	$900 – 1,000
Other PP&E	$50 – 75	$250 – 300	$250 – 300
Dividends, senior notes redemption, capitalized interest, etc.	$150 – 200	$575 – 600	$575 – 600
Cash income taxes	***$550 – 650***	$200 – 300	$200 – 300
Total Cash Outflows	***$2,325 – 2,625***	$6,500 – 7,425	$6,900 – 7,725
Net Cash Change	***$1,725 – 2,025***	***$850 –1,225***	$1,250 – 1,725

(a) The 2008 fourth quarter production and cash flow forecasts reflect anticipated sales by the company of: 1) producing properties for approximately $450 million in a volumetric production payment (VPP); and 2) producing properties in South Texas and undeveloped leasehold in the Marcellus Shale and other areas for approximately $2.3 billion. The 2009 and 2010 production and cash flow forecasts reflect anticipated sales by the company of: 1) producing properties for approximately $1.1 billion in each year in VPP transactions; and 2) undeveloped leasehold or other producing properties for approximately $1.6 billion in each year.

(b) NYMEX natural gas prices have been updated for actual contract prices through October 2008.

(c) Severance tax per mcfe is based on NYMEX prices of $60.00 per bbl of oil and $6.50 to $7.50 per mcf of natural gas during the 2008 fourth quarter; $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during 2009; and $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during 2010.

(d) Excludes expenses associated with noncash stock compensation.

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

(f) 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.

(g) Assumes NYMEX natural gas prices of $6.50 to $7.50 per mcf and NYMEX oil prices of $60.00 per bbl in the 2008 fourth quarter and NYMEX natural gas prices of $7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 per bbl in 2009 and 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:

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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
(v) 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.
(vi) 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.
(vii) 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 (losses) from lifted natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Gains (Losses) from Lifted Swaps ($ millions)	Total Lifted Gain (Loss) per Mcf of Estimated Total Natural Gas Production
Q4 2008	***108.2***	***$9.27***	***190***	***57%***	***$85.2***	***$0.45***
Total 2009(1)	***327.7***	***$9.43***	903	***36%***	($36.7)	($0.04)
Total 2010(1)	422.6	$9.58	1,052	40%	$33.9	$0.03

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below $6.50 covering 9 bcf in 2008 and prices ranging from $5.65 to $7.25 covering 150 bcf in 2009 and $5.45 to $7.40 covering 321 bcf in 2010.

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

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Collars as a % of Estimated Total Natural Gas Production
Q4 2008	26.6	$7.75	$9.32	***190***	***14%***
Total 2009[(1)]	***267.5***	***$7.21***	***$9.27***	903	***30%***
Total 2010[(1)]	25.6	$7.71	$11.46	1,052	2%

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 105 bcf in 2009 and at $6.00 covering 4 bcf in 2010.

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

	Call Options in Bcf's	Avg. NYMEX Call Price	Avg. Premium per mcf	Assuming Natural Gas Production in Bcf's of:	Call Options as a % of Estimated Total Natural Gas Production
Q4 2008	***32.2***	***$10.37***	***$0.74***	***190***	17%
Total 2009	***216.2***	***$11.40***	***$0.63***	903	***24%***
Total 2010	231.8	$10.77	$0.72	1,052	22%

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less*:	Volume in Bcf's	NYMEX plus*:
Q4 2008	32.1	$ 0.45	5.8	$ 0.33
2009	77.1	0.35	16.9	0.28
2010	—	—	10.2	0.26
2011	45.1	0.64	12.1	0.25
2012	43.2	0.48	—	—
Totals	197.5	$ 0.46	45.0	$ 0.27

* 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 ($76 million as of September 30, 2008). 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 in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
Q4 2008	9.7	$4.66	$7.84	($3.17)	***190***	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	903	2%

Note: Not shown above are collars covering 3.7 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 in mbbls	Avg. NYMEX Strike Price	Assuming Oil Production in mbbls of:	Open Swap Positions as a % of Estimated Total Oil Production	Total Gains (Losses) from Lifted Swaps ($ millions)	Total Lifted Gain (Loss) per bbl of Estimated Total Oil Production
Q4 2008(1)	***1,214***	***$78.09***	2,825	***43%***	***($2.3)***	***($0.81)***
Total 2009(1)	***5,728***	***$81.19***	12,000	***48%***	***$38.5***	***$3.21***
Total 2010(1)	4,745	$90.25	13,000	37%	—	—

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 982 mbbls in 2008, from $50.00 to $60.00 covering 6,038 mbbls in 2009 and $60.00 covering 4,745 mbbls in 2010.

Note: Not shown above are written call options covering 768 mbbls of production in 2008 at a weighted average price of $85.86 for a weighted average premium of $4.05, 5,110 mbbls of production in 2009 at a weighed average price of $133.93 for a weighted average premium of $3.90 and 5,110 mbbls of production in 2010 at a weighed average price of $140.00 for a weighted average premium of $4.46.