News Release

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CHESAPEAKE ENERGY CORPORATION PROVIDES OPERATIONAL AND FINANCIAL UPDATE

Company Reduces Drilling Capital Expenditure Budget through 2010 by Approximately $3 Billion and Expects Approximately $2 Billion of Excess Cash Generation in 2009 and 2010 to Be Directed Primarily to Debt Reduction

Lower Capex and Asset and VPP Sales Lead to Lower Production Growth Forecasts for 2008 of 18% from 21% and for 2009 and 2010 of 16% from 19%

Company Closes Fayetteville Shale Joint Venture Transaction with BP America; Discussions Progress on Marcellus Shale Joint Venture; Company Resumes Plans to Sell a $1 Billion Minority Interest in its Midstream Business

Company Provides Hedging Update; Substantial Decline in Natural Gas and Oil Prices Has Led to an Approximate $6 Billion Favorable Mark-to-Market Change in the Company's Hedging Positions Since June 30, 2008

Company Completes Three New Haynesville Shale Wells in September with Average per Well Initial Production Rates Exceeding 10 MMcfe per Day

OKLAHOMA CITY, OKLAHOMA, SEPTEMBER 22, 2008 – Chesapeake Energy Corporation (NYSE:CHK) today announced plans to reduce its drilling capital expenditure (capex) budget during the second half of 2008 through year-end 2010 by approximately $3.2 billion, or 17%, in response to an approximate 50% decrease in natural gas prices since June 30, 2008 and concerns about the possibility of an emerging U.S. natural gas surplus in advance of increased demand from the U.S. transportation sector. Of the $3.2 billion drilling capex reduction, $0.8 billion is attributable to the drilling capex carry associated with the company's recently closed

Fayetteville Shale joint venture with BP America (NYSE:BP), $0.5 billion is attributable to the drilling capex carry anticipated in a Marcellus Shale joint venture and $1.9 billion is attributable to reduced drilling activity. The company plans to reduce its current operated drilling rig count of 157 rigs to approximately 140 rigs by year-end 2008 and expects to keep its rig count relatively flat through 2009 and 2010.

Chesapeake Elects to Temporarily Curtail a Portion of its Current Natural Gas Production and Lowers its Longer-Term Production Growth Forecasts; Company Successfully Completes Three Additional Horizontal Haynesville Shale Wells

In addition to reducing drilling capex, Chesapeake has elected to temporarily curtail a portion of its unhedged natural gas production in the Mid-Continent region due to unusually weak wellhead natural gas prices that are substantially below industry breakeven costs. The company has curtailed approximately 100 million cubic feet (mmcf) per day of net natural gas production (approximately 125-150 mmcf per day gross) and plans to restore this production once natural gas prices recover from recently depressed wellhead price levels of $3.00 - 5.00 per thousand cubic feet (mcf). This curtailment represents approximately 4% of the company's current net natural gas and oil production capacity of over 2.3 billion cubic feet of natural gas equivalent per day (92% natural gas).

The company has also reduced its full-year 2008 production growth estimate to 18% from 21% to account for the temporary curtailment discussed above, the sale of 45 million cubic feet of natural gas equivalent (mmcfe) per day of production associated with its Fayetteville Shale joint venture with BP, the anticipated sale of 60 mmcfe per day of production in the 2008 fourth quarter associated with the company’s fourth volumetric production payment (VPP) and shut-ins in the 2008 third quarter of onshore production associated with natural gas processing plant limitations as a result of damage by Hurricane Ike.

Additionally, as a result of reduced drilling activity levels announced today, the company has lowered its anticipated production growth forecasts in 2009 and 2010 to 16% per year from 19% per year. At these levels, Chesapeake believes its production growth will still remain at or near the top of its large-cap peer group, particularly in light of continued strong drilling results from its shale plays. Notably, during the month of September, Chesapeake completed three additional horizontal Haynesville Shale wells with average per well initial production rates exceeding 10 mmcfe per day bringing its total horizontal Haynesville Shale wells on production to 14.

Chesapeake Closes $1.9 Billion Fayetteville Shale 25% Joint Venture Transaction with BP and Continues Negotiations on Marcellus Shale 25% Joint Venture; Company Resumes Plans to Sell a Minority Interest in its Midstream Business for Approximately $1 Billion to Help Fund Haynesville Midstream Capex

On September 19, 2008, Chesapeake closed its Fayetteville Shale 25% joint venture transaction with BP. In this transaction, the company received $1.1 billion in cash and will receive a further $800 million during the remainder of 2008 and in 2009 through the funding of 100% of Chesapeake’s 75% share of drilling and completion expenditures.

In addition, Chesapeake continues to make progress in its discussions with multiple parties regarding a Marcellus Shale 25% joint venture that is anticipated to be similar in structure to the Plains Exploration & Production (NYSE:PXP) Haynesville Shale and BP Fayetteville Shale transactions. The company anticipates completing a Marcellus Shale joint venture transaction by year-end 2008.

In addition, Chesapeake has recently resumed plans to sell a minority interest in its midstream natural gas business to institutional investors. Projected proceeds of approximately $1 billion will be used to fund a portion of the costs associated with building the midstream infrastructure in various shale plays, primarily in the Haynesville Shale. In preparation for this transaction, the company is in the process of transferring all of its midstream natural gas assets outside of Appalachia, which consist primarily of gas gathering systems and processing assets, into new partnership entities managed by Chesapeake Midstream Partners, L.P. (CMP). CMP is in the process of finalizing a secured revolving credit facility for its operations with an initial borrowing capacity of $500 million. The assets managed by CMP, which are expected to continue growing substantially in future years, should generate annualized cash flow from operating activities of approximately $300 - 350 million in 2009 and $400 - 450 million in 2010. Chesapeake anticipates that in the next few years, CMP will become the largest producer-operated midstream natural gas business in the U.S.

Including planned asset sales and as a result of reduced drilling capex, Chesapeake anticipates generating excess cash of approximately $2 billion in 2009 and 2010 that will be primarily directed to debt reduction.

Natural Gas and Oil Hedging Update

As of June 30, 2008, Chesapeake's natural gas and oil hedging positions had a negative mark-to-market value of approximately $6.5 billion. Subsequent to June 30, the prices of natural gas and oil have significantly declined and Chesapeake's hedging positions had a negative mark-to-market value of approximately $500 million (including settlements for the 2008 third quarter) as of September 18, 2008, or a favorable change of approximately $6.0 billion.

For the second half of 2008 and for the full years 2009 and 2010, Chesapeake has hedged through swaps and collars approximately 83%, 72% and 46% of its expected natural gas and oil production at average prices of $9.30, $9.63 and $9.89 per thousand cubic feet of natural gas equivalent (mcfe), respectively. In addition, Chesapeake has collected approximately $400 million in premiums for written calls with strike prices above current market prices for its natural gas and oil production in the second half of 2008 and for the full years 2009 and 2010.

The company's updated forecasts for 2008 through 2010 are attached to this release in an Outlook dated September 22, 2008, labeled as Schedule "A," which begins on page 6. This Outlook has been changed from the Outlook dated July 31, 2008 (attached as Schedule "B," which begins on page 11) to reflect various updated information.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "During the past ten years, Chesapeake has led the E&P industry in production growth, and through our efforts and those of other leading independent producers, there are now abundant supplies of natural gas in the U.S. market. In fact, we believe there is now sufficient domestic natural gas supply growth to satisfy a growing percentage of the U.S. transportation fuel market through the use of CNG-fueled vehicles. However, until the market has sufficient incentives for service station owners to build out CNG infrastructure, for auto manufacturers to offer new CNG vehicles in large quantities and for consumers to install home refueling devices, retrofit existing vehicles and purchase new CNG vehicles, insufficient natural gas demand exists to prevent periodic declines in wellhead natural gas prices below the industry's breakeven profitability levels.

"Therefore, we believe it is in the best interests of Chesapeake's shareholders to temporarily curtail a portion of our natural gas production, reduce the company's drilling capex and lower our production growth to provide time for rising natural gas demand to catch up with increasing natural gas supply. We have made these decisions even though Chesapeake is well hedged, has one of the lowest cost structures in the large-cap E&P industry and has a substantial portion of its capex budget during the next few years carried by other companies. We will monitor market conditions and bring curtailed natural gas production volumes back on stream as prices improve. We remain confident that natural gas is the single best solution to meeting America's energy, transportation and environmental challenges in the years ahead and we will continue our industry-leading efforts to increase both supply and demand for clean, affordable and abundant American natural gas.

"We are hopeful that many of Chesapeake's shareholders, employees and royalty owners, along with public officials and natural gas consumers across the country, have seen and appreciated the company's new advertising campaign, CNG Now. We strongly believe that natural gas is the cleanest and most affordable alternative to expensive imported oil, has a very large and important role to play in rejuvenating the U.S. auto manufacturing industry, can help lower greenhouse gas emissions and can help reduce the financial burden of high gasoline prices on Americans. We intend to continue our advertising campaign and encourage producers and consumers alike to indicate their support to federal, state and local officials.

"Further, we are pleased that our Fayetteville Shale joint venture transaction with BP is now in place and look forward to completing a similar joint venture in the Marcellus Shale. We are also happy to report that we have resumed efforts to sell a $1 billion minority interest in our midstream natural gas business. Our midstream business has grown substantially over the past three years and is well positioned for further growth as it builds additional gathering infrastructure in the Barnett, Fayetteville and Haynesville Shale plays to support the company's rapid production growth in these areas. Now that the Haynesville Shale's success is more visible to potential midstream equity partners, we believe it is the right time to initiate a new process to bring in an equity partner interested in helping fund anticipated growth in our midstream business.

"Finally, I am also pleased to announce that Chesapeake completed three new horizontal Haynesville Shale wells in September with average initial production rates exceeding 10 mmcfe per day on restricted chokes with high flowing casing pressure. We look forward to initial production commencing from our first PXP joint venture Haynesville Shale well in October and will provide a full update on the Haynesville Shale and other important plays at our Investor and Analyst Meeting in Oklahoma City on October 15 and 16, 2008. This meeting will be webcast so that all investors will be able to learn more about our operations and prospects for future growth."

Conference Call Information

A conference call to discuss this release has been scheduled for Tuesday morning, September 23, 2008, at 9:00 a.m. EDT. The telephone number to access the conference call is **913-312-4374** or toll-free **888-221-9584**. The passcode for the call is **5132124**. 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 noon EDT on September 23, 2008 through midnight EDT on Tuesday, October 7, 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 **5132124**. 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 and selecting the "News & Events" section. The webcast of the conference call will be available on our website for one year.

*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, Haynesville Shale, Fayetteville Shale, Anadarko Basin, Arkoma Basin, 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**.*

This press release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of planned capital expenditures for drilling and other anticipated cash outflows (including amounts budgeted for leasehold and property acquisitions, geophysical costs, compression and other PP&E, midstream assets, dividends, interest and income taxes), expected natural gas and oil production and future expenses, projections of future natural gas and oil prices, and planned asset sales, as well as statements concerning anticipated cash flow and liquidity, expected uses of future excess cash flow, 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 July 10, 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; our ability to compete effectively against strong independent natural gas and oil companies and majors; 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; uncertainties in evaluating natural gas and oil reserves of acquired properties and associated potential liabilities; our ability to effectively consolidate and integrate acquired properties and operations; unsuccessful exploration and development drilling; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; risks associated with our natural gas and oil hedging program, including realizations on hedged natural gas and oil sales that are lower than market prices, collateral required to secure hedging liabilities and losses resulting from counterparty failure; 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.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF September 22, 2008

Quarters Ending September 30, 2008 and December 31, 2008 and Years Ending December 31, 2008, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of September 22, 2008, we are using the following key assumptions in our projections for the third and fourth quarters of 2008 and the full years 2008, 2009 and 2010.

The primary changes from our July 31, 2008 Outlook are in ***italicized bold*** and are explained as follows:

1) Our first guidance for the 2008 fourth quarter has been provided;
2) Projected production volumes have been updated to reflect reduction in rig count and anticipated divestitures;
3) Projected effects of changes in our hedging positions have been updated;
4) Certain cost assumptions and budgeted capital expenditure assumptions have been updated; and
5) Our NYMEX natural gas and oil price assumptions for estimating future operating cash flow have been reduced.

	Quarter Ending 9/30/2008	***Quarter Ending 12/31/2008***	Year Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production[a]					
Natural gas – bcf	***196 – 199***	***197 – 201***	***777 – 781***	***893 – 913***	***1,032 – 1,072***
Oil – mbbls	***2,825***	***2,825***	***11,200***	12,000	13,000
Natural gas equivalent – bcfe	***213 – 216***	***214 – 218***	***844 – 848***	***965 – 985***	***1,110 –1,150***
Daily natural gas equivalent midpoint – mmcfe	***2,330***	***2,350***	***2,310***	***2,670***	***3,095***
Year-over-year production increase	***15.0%***	***5.9%***	***18.0%***	***15.6%***	***15.9%***
NYMEX Prices[b] *(for calculation of realized hedging effects only):*					
Natural gas - $/mcf	***$10.24***	***$7.50***	***$9.18***	***$8.00***	***$8.00***
Oil - $/bbl	***$120.06***	***$110.00***	***$112.99***	$110.00	***$120.00***
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):					
Natural gas - $/mcf	***($0.82)***	***$1.94***	***$0.24***	***$1.04***	***$0.85***
Oil - $/bbl	***($39.97)***	***($28.38)***	***($32.74)***	***($44.74)***	***($28.90)***
Estimated Differentials to NYMEX Prices:					
Natural gas - $/mcf	10 – 14%	***10 – 14%***	10 – 14%	10 – 14%	10 – 14%
Oil - $/bbl	5 – 7%	***5 – 7%***	5 – 7%	5 – 7%	5 – 7%
Operating Costs per Mcfe of Projected Production:					
Production expense	**$1.00 – 1.10**	***$1.00 – 1.10***	***$1.00 – 1.10***	***$1.10 – 1.20***	***$1.15 – 1.25***
Production taxes (~ 5% of O&G revenues)[c]	$0.45 – 0.50	***$0.35 – 0.40***	***$0.40 – 0.45***	***$0.35 – 0.40***	***$0.35 – 0.40***
General and administrative[d]	$0.33 – 0.37	***$0.33 – 0.37***	$0.33 – 0.37	$0.33 – 0.37	$0.33 – 0.37
Stock-based compensation (non-cash)	$0.10 – 0.12	***$0.10 – 0.12***	$0.10 – 0.12	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	$2.35 – 2.40	***$2.30 – 2.35***	$2.30 – 2.40	***$2.20 – 2.30***	***$2.15 – 2.25***
Depreciation of other assets	$0.20 – 0.24	***$0.20 – 0.24***	$0.20 – 0.24	$0.20 – 0.24	$0.20 – 0.24
Interest expense[e]	**$0.35 – 0.40**	***$0.30 – 0.35***	***$0.35 – 0.40***	***$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	$0.09 – 0.11	$0.09 – 0.11
Service operations income	$0.04 – 0.06	***$0.04 – 0.06***	$0.04 – 0.06	$0.04 – 0.06	$0.04 – 0.06
Book Tax Rate	38.5%	***38.5%***	38.5%	38.5%	38.5%
Cash Income Taxes – in millions	–	***$350 - 450***	***$350 – 450***	***$200 – 300***	***$200 – 300***
Equivalent Shares Outstanding – in millions:					
Basic	553 – 557	***560 – 565***	530 - 535	565 - 570	575 - 580
Diluted	593 – 598	***595 – 600***	565 - 570	600 - 605	610 - 615

Cash Flow Projections – in millions	Quarter Ending 9/30/2008	***Quarter Ending 12/31/2008***	Year Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Inflows:					
Operating cash flow before changes in assets and liabilities[f][g]	***$1,250 – 1,350***	***$1,350 – 1,450***	***$5,550 – 5,750***	***$5,650 – 6,250***	***$6,500 – 7,100***
Sale of leasehold and producing properties[a]	***$4,650 – 4,750***	***$1,650 – 1,850***	***$6,550 – 6,850***	***$1,750 – 2,250***	***$750 – 1,250***
Sale of producing properties via VPP's[a]	***$600***	***$550 – 650***	***$1,775 – 1,875***	***$1,100 – 1,300***	***$1,100 – 1,300***
Debt and equity offerings	***$1,585***	***–***	***$4,730***	***–***	***–***
Midstream financings	***$200 – 250***	***$650 – 850***	***$850 – 1,100***	***$650 – 850***	***$650 – 850***
Proceeds from investments and other	***$100 – 150***	***–***	***$275 – 325***	***$775 – 825***	***$150 – 250***
Total Cash Inflows	***$8,385 – 8,685***	***$4,200 – 4,800***	***$19,730 – 20,630***	***$9,925 – 11,475***	***$9,150 – 10,750***
Outflows:					
Drilling	***$1,450 – 1,550***	***$1,200 – 1,300***	***$5,500 – 5,700***	***$4,500 – 5,000***	***$5,000 – 5,500***
Acquisition of leasehold and producing properties	***$4,750 – 5,250***	***$1,000 – 1,500***	***$8,500 – 9,500***	***$2,000 – 2,250***	***$1,250 – 1,750***
Geophysical costs	$75	***$75***	$300	***$225 – 275***	***$225 – 275***
Compression and other PP&E	***$225 – 250***	***$100 – 125***	***$1,000 – 1,050***	***$500 – 550***	***$250 – 300***
Midstream infrastructure	***$275 – 300***	***$375 – 400***	***$1,200 – 1,250***	***$1,350 – 1,500***	***$750 – 950***
Dividends, senior notes redemption, capitalized interest, etc.	$550 – 600	***$150 – 200***	$1,150 – 1,250	$575 – 600	***$500 – 550***
Cash income taxes	***–***	***$350 – 450***	***$350 – 450***	***$200 – 300***	***$200 – $300***
Total Cash Outflows	***$7,325 – 8,025***	***$3,250 – 4,050***	***$18,000 – 19,500***	***$9,350 – 10,475***	***$8,175 – 9,625***
Net Cash Change	***$660 – 1,060***	***$750 – 950***	***$1,130 – 1,730***	***$575 –1,000***	***$975 – 1,125***

(a) The 2008 production and cash flow forecasts reflect sales completed in the 2008 first half and both completed and anticipated sales by the company of: 1) producing properties for $600 million in the 2008 third quarter and approximately $600 million in the 2008 fourth quarter in two volumetric production payment (VPP) transactions; 2) Haynesville Shale undeveloped leasehold for $1.85 billion to PXP in the 2008 third quarter; 3) Arkoma Basin Woodford Shale properties for $1.75 billion to BP in the 2008 third quarter; 4) Arkoma Basin Fayetteville Shale properties for $1.1 billion to BP in the 2008 third quarter and 5) undeveloped leasehold in the Marcellus Shale and other areas for approximately $1.75 billion in the 2008 fourth quarter. The 2009 and 2010 production and cash flow forecasts reflect sales by the company of producing properties for approximately $1.2 billion each year in VPP transactions and undeveloped leasehold for approximately $2.0 billion in 2009 and approximately $1.0 billion in 2010.

(b) NYMEX oil prices have been updated for actual contract prices through August 2008 and NYMEX natural gas prices have been updated for actual contract prices through September 2008.

(c) Severance tax per mcfe is based on NYMEX prices of $120.06 per bbl of oil and $9.50 to $10.50 per mcf of natural gas during Q3 2008; $110.00 per bbl of oil and $7.00 to $8.00 per mcf of natural gas during Q4 2008; $112.99 per bbl of oil and $8.25 to $9.50 per mcf of natural gas during calendar 2008; $110.00 per bbl of oil and $7.00 to $8.50 per mcf of natural gas during 2009; and $120.00 per bbl of oil and $7.00 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 of $7.50 to $8.50 per mcf and NYMEX oil prices of $110.00 per bbl.

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
Q3 2008	154.5	$8.99	***198***	***78%***	$38.8	***$0.20***
Q4 2008	***147.5***	***$9.43***	***199***	***74%***	***$53.4***	***$0.27***
Q3-Q4 2008[(1)]	***302.0***	***$9.21***	***397***	***76%***	***$92.2***	***$0.23***
Total 2009[(1)]	***570.1***	***$9.54***	***903***	***63%***	***($135.9)***	***($0.15)***
Total 2010[(1)]	***470.0***	***$9.70***	***1,052***	***45%***	***($68.9)***	***($0.07)***

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.45 to $7.50 covering 138 bcf in 2008, $5.45 to $7.50 covering 356 bcf in 2009 and $5.45 to $7.50 covering 318 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
Q3 2008	8.3	$8.17	$10.26	***198***	4%
Q4 2008	6.5	$8.04	$10.33	***199***	3%
Q3-Q4 2008	14.8	$8.11	$10.29	***397***	4%
Total 2009[(1)]	***63.9***	***$8.05***	***$11.18***	***903***	***7%***
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 $5.50 to $6.00 covering 38 bcf in 2009 and at $6.00 to $6.50 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
Q3 2008	***25.2***	$10.25	$0.86	***198***	***13%***
Q4 2008	***34.0***	$10.39	***$0.70***	***199***	***17%***
Q3-Q4 2008	***59.2***	$10.32	***$0.78***	***397***	***15%***
Total 2009	***225.5***	$11.37	***$0.61***	***903***	***25%***
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*:
2008	***65.7***	***$ 0.47***	11.6	$ 0.33
2009	**77.1**	**0.35**	16.9	0.28
2010	—	—	10.2	0.26
2011	***32.2***	0.68	12.1	0.25
2012	***30.4***	0.49	—	—
Totals	***205.4***	***$ 0.46***	50.8	***$ 0.28***

* 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 ($102 million as of June 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
Q3 2008	9.7	$4.68	$7.41	($2.74)	***198***	5%
Q4 2008	9.7	$4.66	$7.84	($3.17)	***199***	5%
Q3-Q4 2008	19.4	$4.67	$7.62	($2.95)	***397***	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 Losses from Lifted Swaps ($ millions)	Total Lifted Losses per bbl of Estimated Total Oil Production
Q3 2008	***1,979***	***$76.45***	***2,825***	***70%***	($4.6)	***($1.63)***
Q4 2008	***1,702***	***$77.57***	***2,825***	***60%***	($4.7)	***($1.68)***
Q3-Q4 2008[1]	***3,681***	***$76.97***	***5,650***	***65%***	($9.3)	***($1.66)***
Total 2009[1]	8,395	$82.33	12,000	70%	—	—
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 $65.00 covering 2,148 mbbls in 2008, from $52.50 to $60.00 covering 7,848 mbbls in 2009 and $60.00 covering 4,745 mbbls in 2010.

Note: Not shown above are written call options covering 1,534 mbbls of production in 2008 at a weighted average price of $85.23 for a weighted average premium of $3.34, 3,285 mbbls of production in 2009 at a weighed average price of $122.22 for a weighted average premium of $6.07 and 3,285 mbbls of production in 2010 at a weighed average price of $131.67 for a weighted average premium of $6.94.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF JULY 31, 2008
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF SEPTEMBER 22, 2008

Quarter Ending September 30, 2008 and Years Ending December 31, 2008, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of July 31, 2008, we are using the following key assumptions in our projections for the third quarter of 2008 and the full years 2008, 2009 and 2010.

The primary changes from our July 16, 2008 Outlook are in ***italicized bold*** and are explained as follows:

1) Our first guidance for the 2008 third quarter has been provided;
2) Projected effects of changes in our hedging positions have been updated;
3) Certain cost assumptions and budgeted capital expenditure assumptions have been updated; and
4) Our NYMEX natural gas and oil price assumptions for estimating future operating cash flow have been reduced.

	Quarter Ending 9/30/2008	Year Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production[a]				
Natural gas – bcf	***198 – 204***	791 – 801	943 – 963	1,122 – 1,162
Oil – mbbls	***2,730***	11,000	12,000	13,000
Natural gas equivalent – bcfe	***214 – 220***	857 – 867	1,015 – 1,035	1,200 –1,240
Daily natural gas equivalent midpoint – mmcfe	***2,360***	2,360	2,810	3,340
Year-over-year production increase	***16%***	21%	19%	19%
NYMEX Prices[b] *(for calculation of realized hedging effects only):*				
Natural gas - $/mcf	***$11.04***	***$10.00***	***$10.00***	***$10.00***
Oil - $/bbl	***$110.00***	***$110.47***	***$110.00***	***$110.00***
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):				
Natural gas - $/mcf	***($1.51)***	***($0.42)***	***($0.02)***	***$0.13***
Oil - $/bbl	***$(31.94)***	***($31.02)***	***($33.91)***	***($19.80)***
Estimated Differentials to NYMEX Prices:				
Natural gas - $/mcf	***10 – 14%***	10 – 14%	10 – 14%	10 – 14%
Oil - $/bbl	***5 – 7%***	***5 – 7%***	***5 – 7%***	***5 – 7%***
Operating Costs per Mcfe of Projected Production:				
Production expense	***$0.95 – 1.05***	$0.95 – 1.05	$1.00 – 1.10	$1.05 – 1.15
Production taxes (~ 5% of O&G revenues) [c]	***$0.45 – 0.50***	***$0.45 – 0.50***	***$0.45 – 0.50***	***$0.45 – 0.50***
General and administrative[d]	***$0.33 – 0.37***	$0.33 – 0.37	$0.33 – 0.37	$0.33 – 0.37
Stock-based compensation (non-cash)	***$0.10 – 0.12***	$0.10 – 0.12	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	***$2.35 – 2.40***	***$2.30 – 2.40***	***$2.25 – 2.35***	***$2.20 – 2.30***
Depreciation of other assets	***$0.20 – 0.24***	$0.20 – 0.24	$0.20 – 0.24	$0.20 – 0.24
Interest expense[e]	***$0.45 – 0.50***	***$0.45 – 0.50***	***$0.45 – 0.50***	***$0.45 – 0.50***
Other Income per Mcfe:				
Natural gas and oil marketing income	***$0.09 – 0.11***	$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	$0.04 – 0.06
Book Tax Rate	***38.5%***	38.5%	38.5%	38.5%
Cash Income Taxes – in millions	***–***	***$100 – 250***	***–***	***–***
Equivalent Shares Outstanding – in millions:				
Basic	***553 - 557***	***530 - 535***	***565 - 570***	***575 - 580***
Diluted	***593 - 598***	***565 - 570***	***600 - 605***	***610 - 615***

Cash Flow Projections – in millions	***Quarter Ending 9/30/2008***	Year Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Inflows:				
Operating cash flow before changes in assets and liabilities[f][g]	***$1,200 – 1,300***	***$5,600 – 5,700***	***$6,400 – 7,000***	***$7,600 – 8,900***
Sale of leasehold and producing properties[a]	***$6,750 – 7,250***	***$8,250 – 8,750***	***$2,500 – 3,500***	***$2,500 – 3,500***
Debt and equity offerings	***$1,575***	***$4,725***	***–***	***–***
Proceeds from investments and other	***$75 – 100***	***$425 – 450***	***$550 – 650***	***$550 – 650***
Total Cash Inflows	***$9,600 – 10,225***	***$19,000 – 19,625***	***$9,450 – 11,150***	***$10,650 – 13,050***
Outflows:				
Drilling	***$1,550 – 1,650***	***$5,750 – 6,250***	$6,000 – 6,500	***$6,250 – 6,750***
Acquisition of leasehold and producing properties	***$5,000 – 5,500***	***$8,250 – 8,750***	***$2,000 – 2,250***	***$2,000 – 2,250***
Geophysical costs	***$75***	$300	***$250 – 275***	***$250 – 275***
Midstream, compression and other PP&E	***$400 – 450***	***$2,000 – 2,250***	***$1,000 – 1,250***	***$1,000 – 1,250***
Dividends, Sr. Notes redemption, capitalized interest, etc.	***$550 – 600***	***$1,150 – 1,250***	***$575 – 600***	***$575 – 600***
Cash income taxes	***–***	***$100 – 250***	***–***	***–***
Total Cash Outflows	***$7,575 – 8,275***	***$17,550 – 19,050***	***$9,825 – 10,875***	***$10,075 – 11,125***
Net Cash Change	***$1,950 – 2,025***	***$575 – 1,450***	***($375) – 275***	***$575 – 1,925***

(a) The 2008 forecast reflects sales completed in the 2008 first half and both completed and anticipated sales by the company of: 1) producing properties for $605 million in the 2008 third quarter in a volumetric production payment (VPP) transaction; 2) Haynesville undeveloped leasehold for $1.650 billion in the 2008 third quarter; 3) Arkoma Basin properties for $1.75 billion in the 2008 third quarter; and 4) undeveloped leasehold or producing properties for $3.5 - 4.5 billion in the 2008 second half. The 2009 and 2010 forecasts assume that the company sells undeveloped leasehold or producing properties for $3.0 - 4.0 billion in each year.

(b) NYMEX oil prices have been updated for actual contract prices through June 2008 and NYMEX natural gas prices have been updated for actual contract prices through July 2008.

(c) Severance tax per mcfe is based on NYMEX prices of $100.00 per bbl of oil and $9.50 to $10.50 per mcf of natural gas during Q3 2008; $105.47 per bbl of oil and $9.50 to $10.50 per mcf of natural gas during calendar 2008; and $110.00 per bbl of oil and $9.50 to $10.50 per mcf of natural gas during 2009 and 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 of $9.00 to $11.00 per mcf and NYMEX oil prices of $110.00 per bbl.

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
Q3 2008	***154.5***	***$8.99***	***201***	***77%***	***$38.8***	***$0.19***
Q4 2008	***144.8***	***$9.56***	***213***	***68%***	***$50.4***	***$0.24***
Q3-Q4 2008[1]	***299.3***	***$9.26***	***414***	***72%***	***$89.2***	***$0.22***
Total 2009[1]	***494.1***	***$9.88***	***953***	***52%***	***($154.7)***	***($0.16)***
Total 2010[1]	***269.3***	***$10.02***	***1,142***	***24%***	***($66.3)***	***($0.06)***

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.45 to $7.50 covering 138 bcf in 2008, 5.45 to $7.50 covering 343 bcf in 2009 and $5.45 to $7.50 covering 172 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
Q3 2008	***8.3***	**$8.17**	***$10.26***	***201***	***4%***
Q4 2008	***6.5***	**$8.04**	***$10.33***	***213***	***3%***
Q3-Q4 2008	***14.8***	**$8.11**	***$10.29***	***414***	***4%***
Total 2009[(1)]	***63.9***	***$8.05***	***$11.18***	***953***	***7%***
Total 2010[(1)]	***25.6***	***$7.71***	***$11.46***	***1,142***	***2%***

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.50 to $6.00 covering 38 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
Q3 2008	***28.2***	**$10.25**	***$0.86***	***201***	***14%***
Q4 2008	***34.0***	**$10.39**	***$0.91***	***213***	***16%***
Q3-Q4 2008	***62.2***	**$10.32**	***$0.89***	***414***	***16%***
Total 2009	***225.5***	***$11.37***	***$0.71***	***953***	***24%***
Total 2010	***308.4***	***$10.74***	***$0.71***	***1,142***	***27%***

*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*:
2008	***72.4***	***0.44***	***11.6***	***0.33***
2009	91.1	0.33	16.9	0.28
2010	—	—	10.2	0.26
2011	***34.2***	***0.68***	12.1	0.25
2012	***32.1***	***0.49***	—	—
Totals	***229.8***	***$ 0.44***	***50.8***	***$ 0.28***

* 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 ($102 million as of June 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
Q3 2008	9.7	$4.68	$7.41	($2.74)	***201***	5%
Q4 2008	9.7	$4.66	$7.84	($3.17)	***213***	5%
Q3-Q4 2008	***19.4***	***$4.67***	***$7.62***	***($2.95)***	***414***	***5%***
Total 2009	18.3	$5.18	$7.28	($2.10)	***953***	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 Losses from Lifted Swaps ($ millions)	Total Lifted Losses per bbl of Estimated Total Oil Production
Q3 2008	***2,039***	***76.92***	***2,730***	***75%***	***$(4.6)***	***$(1.69)***
Q4 2008	***1,886***	***79.01***	***2,710***	***70%***	***$(4.7)***	***$(1.75)***
Q3-Q4 2008[(1)]	***3,925***	***$77.93***	***5,440***	***72%***	***$(9.3)***	***$(1.72)***
Total 2009[(1)]	***8,395***	***$82.33***	***12,000***	**70%**	—	—
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 $65.00 covering 2,392 mbbls in 2008, from $52.50 to $60.00 covering 7,848 mbbls in 2009 and $60.00 covering 4,745 mbbls in 2010.

Note: Not shown above are written call options covering 1,472 mbbls of production in 2008 at a weighted average price of $82.50 for a weighted average premium of $3.27, 2,555 mbbls of production in 2009 at a weighed average price of $146.43 for a weighted average premium of $4.98 and 2,555 mbbls of production in 2010 at a weighed average price of $160.71 for a weighted average premium of $3.79.