News Release

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FOR IMMEDIATE RELEASE
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CHESAPEAKE ENERGY CORPORATION REPORTS FINANCIAL AND OPERATIONAL RESULTS FOR THE 2008 SECOND QUARTER

OKLAHOMA CITY, OKLAHOMA, JULY 31, 2008 – Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operating results for the 2008 second quarter. For the quarter, Chesapeake's adjusted net income to common shareholders was $479 million ($0.89 per fully diluted common share) and adjusted ebitda was $1.435 billion, increases of 40% and 23%, respectively, over the 2007 second quarter. Chesapeake's adjusted net income to common shareholders excludes the following items that are typically not included in published estimates of the company's financial results by certain securities analysts:

- an unrealized noncash after-tax mark-to-market (MTM) loss of $2.085 billion from future period natural gas, oil and interest rate hedges primarily as a result of higher natural gas and oil prices as of June 30, 2008 compared to March 31, 2008; and
- a reduction of net income available to common shareholders of $43 million resulting from exchanges of the company's preferred stock for common stock that reduced future preferred stock dividend payment requirements.

Including the items noted above, Chesapeake reported a net loss to common shareholders during the quarter of $1.649 billion (a loss of $3.17 per fully diluted common share), operating cash flow of $1.443 billion (defined as cash flow from operating activities before changes in assets and liabilities) and negative ebitda of $1.971 billion (defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense) on negative revenue of $455 million and production of 212 billion cubic feet of natural gas equivalent (bcfe).

Recent extreme volatility in natural gas and oil prices has created wide swings in the MTM value of Chesapeake's hedges. For example, from June 30, 2008 to July 25, 2008, the MTM value of the company's hedges moved in the company's favor by approximately $4.7 billion. Should prices on September 30, 2008 be the same as prices on July 25, 2008, substantially all of the 2008 second quarter unrealized MTM loss would be reversed and reported as a unrealized MTM gain in the 2008 third quarter. Because of such pricing volatility and in order to secure strong and predictable profit margins, Chesapeake prefers to hedge much of its exposure to natural gas and oil price swings on a rolling 24-month basis. Chesapeake's hedging agreements have been structured so that cash margin requirements are generally not required by the 22 counterparties it uses to hedge its production.

A reconciliation of operating cash flow, ebitda, adjusted ebitda and adjusted net income to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 16 – 19 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2008 second quarter and compares them to results during the 2008 first quarter and the 2007 second quarter. The 2008 second quarter results reflect the sale of 47 million cubic feet of natural gas equivalent (mmcfe) per day of production in a volumetric production payment (VPP) transaction as of May 1, 2008.

	Three Months Ended:		
	6/30/08	3/31/08	6/30/07
Average daily production (in mmcfe)	2,328	2,244	1,868
Natural gas as % of total production	92	92	92
Natural gas production (in bcf)	195.0	187.8	156.1
Average realized natural gas price ($/mcf) (a)	8.18	9.05	7.97
Oil production (in mbbls)	2,816	2,746	2,324
Average realized oil price ($/bbl) (a)	76.96	74.73	65.37
Natural gas equivalent production (in bcfe)	211.9	204.2	170.0
Natural gas equivalent realized price ($/mcfe) (a)	8.55	9.33	8.21
Natural gas and oil marketing income ($/mcfe)	.12	.11	.11
Service operations income ($/mcfe)	.04	.03	.07
Production expenses ($/mcfe)	(1.03)	(.98)	(.90)
Production taxes ($/mcfe)	(.41)	(.37)	(.31)
General and administrative costs ($/mcfe) (b)	(.38)	(.29)	(.25)
Stock-based compensation ($/mcfe)	(.10)	(.09)	(.07)
DD&A of natural gas and oil properties ($/mcfe)	(2.47)	(2.52)	(2.60)
D&A of other assets ($/mcfe)	(.19)	(.18)	(.23)
Interest expense ($/mcfe) (a)	(.36)	(.43)	(.54)
Operating cash flow ($ in millions) (c)	1,443	1,512	1,076
Operating cash flow ($/mcfe)	6.81	7.40	6.33
Adjusted ebitda ($ in millions) (d)	1,435	1,570	1,167
Adjusted ebitda ($/mcfe)	6.77	7.69	6.86
Net income (loss) to common shareholders ($ in millions)	(1,649)	(143)	492
Earnings (loss) per share – assuming dilution ($)	(3.17)	(.29)	1.01
Adjusted net income to common shareholders ($ in millions) (e)	479	561	342
Adjusted earnings per share – assuming dilution ($)	.89	1.09	.71

(a) includes the effects of realized gains or (losses) from hedging, but does not include the effects of unrealized gains or (losses) from hedging

(b) excludes expenses associated with noncash stock-based compensation
(c) defined as cash flow provided by operating activities before changes in assets and liabilities
(d) defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on page 18
(e) defined as net income (loss) available to common shareholders, as adjusted to remove the effects of certain items detailed on page 18

Chesapeake Becomes the Largest Producer of Natural Gas in the U.S.; Natural Gas and Oil Production Sets Record for 28th Consecutive Quarter; 2008 Second Quarter Average Daily Production Increases 4% over 2008 First Quarter Production and 25% over 2007 Second Quarter Production

Daily production for the 2008 second quarter averaged 2.328 bcfe, an increase of 84 mmcfe, or 4%, over the 2.244 bcfe produced per day in the 2008 first quarter and an increase of 460 mmcfe, or 25%, over the 1.868 bcfe produced per day in the 2007 second quarter. Adjusted for the company's year-end 2007 and second quarter 2008 VPP sales of 55 and 47 mmcfe per day, respectively, Chesapeake's sequential and year-over-year production growth rates were 5% and 29%, respectively.

Chesapeake's average daily production for the 2008 second quarter consisted of 2.143 billion cubic feet of natural gas (bcf) and 30,945 barrels of oil and natural gas liquids (bbls). The company's 2008 second quarter production of 211.9 bcfe was comprised of 195 bcf (92% on a natural gas equivalent basis) and 2.82 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis). Based on 2008 second quarter results reported by the industry to date, Chesapeake believes it has become the largest producer of natural gas in the U.S.

The 2008 second quarter was Chesapeake's 28th consecutive quarter of sequential U.S. production growth. Over these 28 quarters, Chesapeake's U.S. production has increased 488%, for an average compound quarterly growth rate of 6.5% and an average compound annual growth rate of 29%.

Natural Gas and Oil Proved Reserves Reach Record Level of 12.2 Tcfe; During 2008 First Half, Company Adds 1.3 Tcfe of Net Proved Reserves for a Reserve Replacement Rate of 410% at an Average Drilling and Net Acquisition Cost of $1.49 per Mcfe

Chesapeake began 2008 with estimated proved reserves of 10.879 trillion cubic feet of natural gas equivalent (tcfe) and ended the second quarter with 12.170 tcfe, an increase of 1.291 tcfe, or 12%. During the 2008 first half, Chesapeake replaced 416 bcfe of production with an estimated 1.707 tcfe of new proved reserves for a reserve replacement rate of 410%. Reserve replacement through the drillbit was 1.751 tcfe, or 421% of production. This includes 779 bcfe of positive performance revisions (including 703 bcfe related to infill drilling and increased density locations) and 182 bcfe of positive revisions resulting from natural gas and oil price increases between December 31, 2007 and June 30, 2008. Acquisitions of proved reserves completed during the 2008 first half were 85 bcfe at a cost of $122 million, or $1.44 per mcfe, while sales of proved reserves during the 2008 first half totaled 129 bcfe for proceeds of $712 million, or $5.53 per mcfe. Sales of undeveloped leasehold during the 2008 first half generated proceeds of $158 million.

Chesapeake's total drilling and net acquisition costs for the 2008 first half were $1.49 per mcfe. This calculation excludes costs of $2.5 billion for the acquisition of unproved properties and leasehold (net of sales), $168 million for capitalized interest on unproved properties, $150 million for seismic, and $18 million relating to tax basis step-up and asset retirement obligations, as well as positive revisions of proved reserves from higher natural gas and oil prices. Excluding these items and acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during the 2008 first half were $1.82 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 14 of this release.

During the 2008 first half, Chesapeake continued the industry's most active drilling program and drilled 988 gross operated wells (837 net with an average working interest of 84.7%) and participated in another 856 gross wells operated by other companies (95 net with an average working interest of 11.1%). The company's drilling success rate was 99% for company-operated wells and 96% for non-operated wells. Also during the 2008 first half, Chesapeake invested $2.486 billion in operated wells (using an average of 143 operated rigs) and $371 million in non-operated wells (using an average of 104 non-operated rigs) for total drilling, completing and equipping costs of $2.857 billion.

As of June 30, 2008, Chesapeake's estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10), were $51.5 billion using field differential adjusted prices of $11.81 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $13.10 per mcf) and $135.42 per bbl (based on a NYMEX quarter-end price of $140.02 per bbl). Chesapeake's PV-10 changes by approximately $420 million for every $0.10 per mcf change in natural gas prices and approximately $60 million for every $1.00 per bbl change in oil prices. Chesapeake's enterprise value (market equity value plus long-term debt less working capital excluding current portion of derivative assets and liabilities) as of June 30, 2008 was approximately $51.8 billion.

By comparison, the December 31, 2007 PV-10 of the company's proved reserves was $20.6 billion ($15.0 billion applying the SFAS 69 standardized measure) using field differential adjusted prices of $6.19 per mcf (based on a NYMEX year-end price of $6.80 per mcf) and $90.58 per bbl (based on a NYMEX year-end price of $96.00 per bbl). The June 30, 2007 PV-10 of the company's proved reserves was $18.8 billion using field differential adjusted prices of $6.25 per mcf (based on a NYMEX quarter-end price of $6.80 per mcf) and $65.41 per bbl (based on a NYMEX quarter-end price of $70.33 per bbl).

The company calculates the standardized measure of future net cash flows in accordance with SFAS 69 only at year end because applicable income tax information on properties, including recently acquired natural gas and oil interests, is not readily available at other times during the year. As a result, the company is not able to reconcile the interim period-end values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects.

In addition to the PV-10 value of its proved reserves and the very significant value of its undeveloped leasehold, particularly in the Haynesville, Barnett, Fayetteville and Marcellus shale plays, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments and other non-current assets) was $4.6 billion as of June 30, 2008, $3.1 billion as of December 31, 2007 and $2.8 billion as of June 30, 2007.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2008 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.18 per mcf and $76.96 per bbl, for a realized natural gas equivalent price of $8.55 per mcfe. Realized gains and losses from natural gas and oil hedging activities during the 2008 second quarter generated a $1.55 loss per mcf and a $42.85 loss per bbl for a 2008 second quarter realized hedging loss of $423 million, or $2.00 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2008 second quarter were a negative $1.21 per mcf and a negative $4.17 per bbl.

By comparison, average prices realized during the 2007 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $7.97 per mcf and $65.37 per bbl, for a realized natural gas equivalent price of $8.21 per mcfe. Realized gains from natural gas and oil hedging activities during the 2007 second quarter generated a $1.19 gain per mcf and a $5.27 gain per bbl for a 2007 second quarter realized hedging gain of $197 million, or $1.16 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2007 second quarter were a negative $0.77 per mcf and a negative $4.93 per bbl.

The following tables compare Chesapeake's open hedge position through swaps and collars as of July 31, 2008 to those previously announced as of May 1, 2008. Depending on changes in natural gas and oil futures markets and management's view of underlying natural gas and oil supply and demand trends, Chesapeake may either increase or decrease its hedging positions at any time in the future without notice.

Open Swap Positions as of July 31, 2008

Quarter or Year	Natural Gas % Hedged	Natural Gas $ NYMEX	Oil % Hedged	Oil $ NYMEX
2008 Q3	82%	8.90	75%	76.92
2008 Q4	73%	9.45	70%	79.01
2008 Q3-Q4 Total	77%	9.16	72%	77.93
2009 Total	54%	9.79	70%	82.33
2010 Total	24%	10.02	37%	90.25

Open Natural Gas Collar Positions as of July 31, 2008

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2008 Q3	4%	8.17	10.26
2008 Q4	3%	8.04	10.33
2008 Q3-Q4 Total	4%	8.11	10.29
2009 Total	7%	8.05	11.18

Open Swap Positions as of May 1, 2008

Quarter or Year	Natural Gas % Hedged	Natural Gas $ NYMEX	Oil % Hedged	Oil $ NYMEX
2008 Q2	78%	8.58	70%	75.58
2008 Q3	79%	8.87	75%	76.92
2008 Q4	71%	9.42	67%	79.01
2008 Q2-Q4 Total	76%	8.96	71%	77.16
2009 Total	52%	9.37	70%	82.33
2010 Total	20%	9.56	37%	90.25

Open Natural Gas Collar Positions as of May 1, 2008

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2008 Q2	6%	8.27	9.92
2008 Q3	5%	8.27	9.92
2008 Q4	4%	8.20	9.91
2008 Q2-Q4 Total	5%	8.25	9.92
2009 Total	5%	8.14	10.82

Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $5.45 to $7.50 per mcf covering 138 bcf in 2008, $5.45 to $7.50 per mcf covering 343 bcf in 2009 and $5.45 to $7.50 per mcf covering 172 bcf in 2010. Certain open natural gas collar positions include three-way collars that include written put options with strike prices ranging from $5.50 to $6.00 per mcf covering 38 bcf in 2009 and at $6.00 per mcf covering 4 bcf in 2010. Also, certain open oil swap positions include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45 to $65 per bbl covering 2 mmbbls in 2008, from $53 to $60 per bbl covering 8 mmbbls in 2009 and $60 per bbl covering 5 mmbbls in 2010.

The company's updated forecasts for 2008 through 2010 are attached to this release in an Outlook dated July 31, 2008, labeled as Schedule "A," which begins on page 20. This Outlook has been changed from the Outlook dated July 16, 2008 (attached as Schedule "B," which begins on page 25) to reflect various updated information.

Chesapeake's Leasehold and 3-D Seismic Inventories Increase to 14.9 Million Net Acres and 20.8 Million Acres; Risked Unproved Reserves in the Company's Inventory Reach 48 Tcfe While Unrisked Unproved Reserves Reach 147 Tcfe

Since 2000, Chesapeake has invested $12.2 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (14.9 million net acres) and 3-D seismic (20.8 million acres) in the U.S. On this leasehold, Chesapeake owns an estimated 4.1 tcfe of proved undeveloped reserves and approximately 47.7 tcfe of risked unproved reserves (147 tcfe of unrisked unproved reserves). The company is currently using 156 operated drilling rigs to further develop its inventory of approximately 34,000 net drillsites, representing more than a 10-year inventory of drilling projects. The following summaries highlight the company's activities in its four major shale plays:

Fort Worth Barnett Shale (North Texas): The Fort Worth Barnett Shale is currently the largest and most prolific unconventional gas resource play in the U.S. In this play, Chesapeake is the second-largest producer of natural gas, the most active driller and the largest leasehold owner in the Core and Tier 1 sweet spots of Tarrant, Johnson and western Dallas counties. During the 2008 second quarter, Chesapeake's average daily net production of 466 mmcfe in the play increased approximately 125% over the 2007 second quarter and approximately 13% over the 2008 first quarter. Chesapeake is currently producing approximately 500 mmcfe net per day from the play and anticipates reaching at least 675 mmcfe net per day by year-end 2008. Chesapeake is currently using approximately 45 operated rigs to further develop its 280,000 net acres of leasehold, of which 240,000 net acres are located in the prime Core and Tier 1 areas.

Haynesville Shale (Northwest Louisiana, East Texas): Chesapeake continues to experience outstanding drilling results in its recent significant Haynesville Shale discovery in Northwest Louisiana and East Texas. Based on its geoscientific, petrophysical and engineering research during the past two years, including analysis of more than 100 wells drilled through the formation by others in the industry, as well as the results of 11 horizontal wells Chesapeake has completed to date, the company believes the Haynesville Shale play will become the largest discovery of natural gas in the U.S. Chesapeake is currently producing approximately 35 mmcfe net per day (45 mmcfe gross) from the play and anticipates reaching at least 75 mmcfe net per day by year-end 2008. Chesapeake is currently using eight operated rigs to further develop its 450,000 net acres of Haynesville Shale leasehold and anticipates operating at least 12 rigs by year-end 2008. The company continues to acquire leasehold in the play with its 20% partner, Plains Exploration & Production Company (PXP).

Fayetteville Shale (Arkansas): In the Fayetteville Shale, Chesapeake is the second-largest leasehold owner in the Core and Tier 1 area of the play. During the 2008 second quarter, Chesapeake's average daily net production of 136 mmcfe in the play increased approximately 475% over the 2007 second quarter and approximately 20% over the 2008 first quarter. Chesapeake is currently producing approximately 150 mmcfe net per day from the play and anticipates reaching at least 200 mmcfe net per day by year-end 2008. Chesapeake is currently using 17 operated rigs to further develop its 550,000 net acres of Core and Tier 1 Fayetteville leasehold and anticipates operating up to 21 rigs by year-end 2008.

Marcellus Shale (West Virginia, Pennsylvania and New York): Chesapeake is the largest leasehold owner in the Marcellus play that spans from West Virginia to southern New York with 1.6 million prospective net acres. During the quarter, Chesapeake completed two horizontal Marcellus wells in West Virginia that together are producing approximately 7 mmcfe per day gross and have combined estimated gross proved reserves of approximately 11 bcfe. The company is pleased with its drilling results to date and is planning to significantly increase its Marcellus Shale drilling activity during the remainder of 2008 and in 2009.

Company Agrees to Sell 93 Bcfe of Proved Reserves for Proceeds of Approximately $605 Million, or $6.50 per Mcfe, in its Second 2008 Volumetric Production Payment Transaction

The company has recently agreed to sell certain interests in Chesapeake-operated long-lived producing assets in the Anadarko Basin in its second volumetric production payment transaction in 2008. Chesapeake will sell assets with estimated proved reserves of approximately 93 bcfe and current net production of approximately 50 mmcfe per day for proceeds of approximately $605 million, or $6.50 per mcfe. Chesapeake will retain drilling rights on the properties below currently producing intervals and retains all remaining production after approximately 11 years. For accounting purposes, the transaction will be treated as a sale and the company's proved reserves and future production will be reduced accordingly. The transaction is expected to close in early August 2008. The company also plans to pursue other undeveloped leasehold sales to high-grade its inventory and monetizations of mature producing properties as needs and opportunities arise.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report our financial and operational results for the 2008 second quarter. Despite the sale of 47 mmcfe per day of production during the quarter, our production increased 4% sequentially and 25% year over year. In addition, the company's ability to replace its 2008 first half production by over 400% at a drilling and net acquisition cost of only $1.49 demonstrates the value creation capabilities of the Chesapeake drilling machine to continue finding and developing very significant quantities of proved reserves at a very low cost. Given our strong 2008 first half operating performance, we remain confident that we can reach our goal of owning 13 tcfe of estimated proved reserves by year-end 2008 and 15 tcfe of estimated proved reserves by year-end 2009. Our ability to convert leasehold into annual increases of 2.0 to 2.5 tcfe of proved reserves is the foundation for our belief that Chesapeake can continue increasing its net asset value by at least $10 billion per year, assuming NYMEX natural gas prices average above $8.00 per mcf.

"We are also excited to provide updated information on our Barnett, Haynesville, Fayetteville and Marcellus shale plays. All of them are working exceptionally well and, in many respects, we have just scratched the surface of the potential of these plays, especially the Haynesville Shale. Our most recent Haynesville Shale well, the Milton Crow 27-1H, is producing approximately 14 mmcfe per day on a 24/64 choke at flowing casing pressure of more than 5,800 psi. We have now completed 11 horizontal wells in the Haynesville Shale and our current combined gross production from these 11 wells is approximately 45 mmcfe per day. We are extremely pleased with the data points we have seen in the play to date and are eager to begin ramping up our drilling activity with our partner, PXP. By the end of this year, we anticipate using 12 rigs to develop our 450,000 net acres of leasehold in the play and, on average, should be able to complete a new Haynesville well every five days.

"Finally, our asset monetization program is enabling us to high-grade our asset base, reduce financial risk, decrease our DD&A rate and increase our profitability per unit of production, thereby increasing our returns on capital and advancing future value creation to the present. We anticipate closing on more than $7.5 billion of such asset monetizations during the 2008 second half."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, August 1, 2008, at 9:00 a.m. EDT. The telephone number to access the conference call is **913-312-1398** or toll-free **888-230-5549**. The passcode for the call is **1569824**. 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 August 1, 2008 through midnight EDT on Friday, August 15, 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 **1569824**. 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.

This press release and the accompanying Outlooks include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, projections of future natural gas and oil prices, planned capital expenditures for drilling, leasehold acquisitions and seismic data and planned asset sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair value of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These *market prices are subject to significant volatility. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.*

Factors that could cause actual results to differ materially from expected results are described 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; 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.

The SEC has generally permitted natural gas and oil companies, in filings made with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the term "unproved" to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third-party engineers or appraisers.

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, Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States. Additional information is available at www.chk.com.

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

THREE MONTHS ENDED:	June 30, 2008		June 30, 2007	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas and oil sales [(a)]	2,233	10.54	1,199	7.04
Natural gas and oil realized hedging gain (loss) [(a)]	(423)	(2.00)	197	1.16
Natural gas and oil unrealized hedging gain (loss) [(a)]	(3,404)	(16.07)	152	0.89
Natural gas and oil marketing sales	1,099	5.19	523	3.08
Service operations revenue	40	0.19	34	0.20
Total Revenues	(455)	(2.15)	2,105	12.37
OPERATING COSTS:				
Production expenses	219	1.03	153	0.90
Production taxes	88	0.41	53	0.31
General and administrative expenses	101	0.48	54	0.32
Natural gas and oil marketing expenses	1,075	5.07	504	2.97
Service operations expense	32	0.15	23	0.13
Natural gas and oil depreciation, depletion and amortization	523	2.47	442	2.60
Depreciation and amortization of other assets	40	0.19	40	0.23
Total Operating Costs	2,078	9.80	1,269	7.46
INCOME (LOSS) FROM OPERATIONS	(2,533)	(11.95)	836	4.91
OTHER INCOME (EXPENSE):				
Interest and other income	(1)	(0.01)	1	0.01
Interest expense	(63)	(0.30)	(84)	(0.50)
Gain on sale of investment	—	—	83	0.49
Total Other Income (Expense)	(64)	(0.31)	—	—
INCOME (LOSS) BEFORE INCOME TAXES	(2,597)	(12.26)	836	4.91
Income Tax Expense (Benefit):				
Current	3	0.01	11	0.06
Deferred	(1,003)	(4.73)	307	1.80
Total Income Tax Expense (Benefit)	(1,000)	(4.72)	318	1.86
NET INCOME (LOSS)	(1,597)	(7.54)	518	3.05
Preferred stock dividends	(9)	(0.04)	(26)	(0.15)
Loss on conversion/exchange of preferred stock	(43)	(0.20)	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	(1,649)	(7.78)	492	2.90
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (3.17)		$ 1.09	
Assuming dilution	$ (3.17)		$ 1.01	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	521		452	
Assuming dilution	521		515	

(a) These components of revenue are combined and presented as "natural gas and oil sales" in our financial statements filed with the Securities and Exchange Commission presented in accordance with generally accepted accounting principles.

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

SIX MONTHS ENDED:	June 30, 2008 $	June 30, 2008 $/mcfe	June 30, 2007 $	June 30, 2007 $/mcfe
REVENUES:				
Natural gas and oil sales [(a)]	3,925	9.43	2,200	6.79
Natural gas and oil realized hedging gain (loss) [(a)]	(208)	(0.50)	630	1.95
Natural gas and oil unrealized hedging gain (loss) [(a)]	(4,538)	(10.90)	(158)	(0.49)
Natural gas and oil marketing sales	1,895	4.55	945	2.92
Service operations revenue	82	0.20	67	0.21
Total Revenues	1,156	2.78	3,684	11.38
OPERATING COSTS:				
Production expenses	419	1.01	295	0.91
Production taxes	163	0.39	95	0.29
General and administrative expenses	180	0.44	107	0.33
Natural gas and oil marketing expenses	1,849	4.44	911	2.82
Service operations expense	67	0.16	44	0.14
Natural gas and oil depreciation, depletion and Amortization	1,038	2.49	835	2.58
Depreciation and amortization of other assets	77	0.19	76	0.23
Total Operating Costs	3,793	9.12	2,363	7.30
INCOME (LOSS) FROM OPERATIONS	(2,637)	(6.34)	1,321	4.08
OTHER INCOME (EXPENSE):				
Interest and other income	(11)	(0.03)	10	0.03
Interest expense	(163)	(0.39)	(162)	(0.50)
Gain on sale of investment	—	—	83	0.26
Total Other Income (Expense)	(174)	(0.42)	(69)	(0.21)
INCOME (LOSS) BEFORE INCOME TAXES	(2,811)	(6.76)	1,252	3.87
Income Tax Expense (Benefit):				
Current	3	—	11	0.03
Deferred	(1,085)	(2.61)	465	1.44
Total Income Tax Expense (Benefit)	(1,082)	(2.61)	476	1.47
NET INCOME (LOSS)	(1,729)	(4.15)	776	2.40
Preferred stock dividends	(20)	(0.05)	(52)	(0.16)
Loss on conversion/exchange of preferred stock	(43)	(0.11)	—	—
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	(1,792)	(4.31)	724	2.24
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (3.54)		$ 1.60	
Assuming dilution	$ (3.54)		$ 1.51	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	507		452	
Assuming dilution	507		515	

(a) These components of revenue are combined and presented as "natural gas and oil sales" in our financial statements filed with the Securities and Exchange Commission presented in accordance with generally accepted accounting principles.

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

	June 30, 2008	December 31, 2007
Cash	$ —	$ 1
Other current assets	3,175	1,395
Total Current Assets	3,175	1,396
Property and equipment (net)	33,463	28,337
Other assets	1,385	1,001
Total Assets	$ 38,023	$ 30,734
Current liabilities	$ 7,297	$ 2,760
Long-term debt, net	13,014	10,950
Asset retirement obligation	254	236
Other long-term liabilities	3,677	692
Deferred tax liability	3,505	3,966
Total Liabilities	27,747	18,604
Stockholders' Equity	10,276	12,130
Total Liabilities & Stockholders' Equity	$ 38,023	$ 30,734
Common Shares Outstanding (in millions)	545	511

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

	June 30, 2008	% of Total Book Capitalization	December 31, 2007	% of Total Book Capitalization
Total debt, net	$ 13,704	57%	$ 10,950	47%
Stockholders' equity	10,276	43%	12,130	53%
Total	$ 23,980	100%	$ 23,080	100%

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2008 ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
($ in millions, except per-unit data)
(unaudited)

	Cost	Reserves (in bcfe)	$/mcfe
Exploration and development costs	$ 2,857	1,569[a]	1.82
Acquisition of proved properties	122	85	1.44
Sale of proved properties	(712)	(129)	5.53
Drilling and net acquisition cost	2,267	1,525	1.49
Revisions – price	—	182	—
Acquisition of unproved properties and leasehold	2,638	—	—
Sale of unproved properties and leasehold	(158)	—	—
Net leasehold and unproved property acquisition	2,480	—	—
Capitalized interest on leasehold and unproved property	168	—	—
Geological and geophysical costs	150	—	—
Geological, geophysical and capitalized interest	318	—	—
Subtotal	5,065	1,707	2.97
Tax basis step-up	12	—	—
Asset retirement obligation and other	6	—	—
Total	$ 5,083	1,707	2.98

(a) Includes 779 bcfe of positive performance revisions (703 bcfe relating to infill drilling and increased density locations and 76 bcfe of other performance related revisions) and excludes positive revisions of 182 bcfe resulting from natural gas and oil price increases between December 31, 2007, and June 30, 2008.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
SIX MONTHS ENDED JUNE 30, 2008
(unaudited)

	Bcfe
Beginning balance, 01/01/08	10,879
Production	(416)
Acquisitions	85
Divestitures	(129)
Revisions – performance	779
Revisions – price	182
Extensions and discoveries	790
Ending balance, 06/30/08	12,170
Reserve replacement	1,707
Reserve replacement ratio [a]	410%

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

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

	THREE MONTHS ENDED June 30,		SIX MONTHS ENDED June 30,	
	2008	**2007**	**2008**	**2007**
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 1,896	$ 1,059	$ 3,329	$ 1,947
Natural gas derivatives – realized gains (losses)	(302)	185	(34)	600
Natural gas derivatives – unrealized gains (losses)	(2,526)	167	(3,528)	(131)
Total Natural Gas Sales	(932)	1,411	(233)	2,416
Oil sales	337	140	596	253
Oil derivatives – realized gains (losses)	(121)	12	(174)	30
Oil derivatives – unrealized gains (losses)	(878)	(15)	(1,010)	(27)
Total Oil Sales	(662)	137	(588)	256
Total Natural Gas and Oil Sales	$ (1,594)	$ 1,548	$ (821)	$ 2,672
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 9.73	$ 6.78	$ 8.70	$ 6.56
Oil ($ per bbl)	$ 119.81	$ 60.10	$ 107.13	$ 56.60
Natural gas equivalent ($ per mcfe)	$ 10.54	$ 7.05	$ 9.43	$ 6.80
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 8.18	$ 7.97	$ 8.61	$ 8.58
Oil ($ per bbl)	$ 76.96	$ 65.37	$ 75.86	$ 63.34
Natural gas equivalent ($ per mcfe)	$ 8.55	$ 8.21	$ 8.93	$ 8.74
Interest Expense ($ in millions):				
Interest	$ 81	$ 91	$ 168	$ 166
Derivatives – realized (gains) losses	(4)	—	(4)	2
Derivatives – unrealized (gains) losses	(14)	(7)	(1)	(6)
Total Interest Expense	$ 63	$ 84	$ 163	$ 162

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

THREE MONTHS ENDED:	**June 30, 2008**	**June 30, 2007**
Beginning cash	$ 1	$ 4
Cash provided by operating activities	1,256	1,145
Cash (used in) investing activities	(3,654)	(2,134)
Cash provided by financing activities	2,397	989
Ending cash	—	4

SIX MONTHS ENDED:	**June 30, 2008**	**June 30, 2007**
Beginning cash	$ 1	$ 3
Cash provided by operating activities	2,754	2,122
Cash (used in) investing activities	(6,329)	(4,003)
Cash provided by financing activities	3,574	1,882
Ending cash	—	4

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

THREE MONTHS ENDED:	June 30, 2008	March 31, 2008	June 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,256	$ 1,498	$ 1,145
Adjustments:			
Changes in assets and liabilities	187	14	(69)
OPERATING CASH FLOW*	$ 1,443	$ 1,512	$ 1,076

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

THREE MONTHS ENDED:	June 30, 2008	March 31, 2008	June 30, 2007
NET INCOME (LOSS)	$ (1,597)	$ (132)	$ 518
Income tax expense (benefit)	(1,000)	(82)	318
Interest expense	63	101	84
Depreciation and amortization of other assets	40	36	40
Natural gas and oil depreciation, depletion and amortization	523	515	442
EBITDA**	$ (1,971)	$ 438	$ 1,402

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

THREE MONTHS ENDED:	June 30, 2008	March 31, 2008	June 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,256	$ 1,498	$ 1,145
Changes in assets and liabilities	187	14	(69)
Interest expense	63	101	84
Unrealized gains (losses) on natural gas and oil derivatives	(3,404)	(1,132)	152
Other non-cash items	(73)	(43)	90
EBITDA	$ (1,971)	$ 438	$ 1,402

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

SIX MONTHS ENDED:	June 30, 2008	June 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,754	$ 2,122
Adjustments:		
Changes in assets and liabilities	200	78
OPERATING CASH FLOW*	$ 2,954	$ 2,200

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

SIX MONTHS ENDED:	June 30, 2008	June 30, 2007
NET INCOME (LOSS)	$ (1,729)	$ 776
Income tax expense (benefit)	(1,082)	476
Interest expense	163	162
Depreciation and amortization of other assets	77	76
Natural gas and oil depreciation, depletion and amortization	1,038	835
EBITDA**	$ (1,533)	$ 2,325

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

SIX MONTHS ENDED:	June 30, 2008	June 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,754	$ 2,122
Changes in assets and liabilities	200	78
Interest expense	163	162
Unrealized gains (losses) on natural gas and oil derivatives	(4,538)	(158)
Other noncash items	(112)	121
EBITDA	$ (1,533)	$ 2,325

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

THREE MONTHS ENDED:	June 30, 2008	March 31, 2008	June 30, 2007
Net income (loss) available to common shareholders	$ (1,649)	$ (143)	$ 492
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	2,085	704	(99)
Gain on sale of investment, net of cash	—	—	(51)
Loss on conversion/exchange of preferred stock	43	—	—
Adjusted net income available to common shareholders*	479	561	342
Preferred stock dividends	9	11	26
Interest on 2.75% contingent convertible notes, net of tax	3	—	—
Total adjusted net income	$ 491	$ 572	$ 368
Weighted average fully diluted shares outstanding**	553	524	515
Adjusted earnings per share assuming dilution*	$ 0.89	$ 1.09	$ 0.71

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

(a) Management uses adjusted net income available to common to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
(b) Adjusted net income available to common is more comparable to earnings estimates provided by securities analysts.
(c) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

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

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

THREE MONTHS ENDED:	June 30, 2008	March 31, 2008	June 30, 2007
EBITDA	$ (1,971)	$ 438	$ 1,401
Adjustments, before tax:			
Unrealized (gains) losses on natural gas and oil derivatives	3,406	1,132	(151)
Gain on sale of investment	—	—	(83)
Adjusted ebitda*	$ 1,435	$ 1,570	$ 1,167

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

(a) Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
(b) Adjusted ebitda is more comparable to estimates provided by securities analysts.
(c) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

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

SIX MONTHS ENDED:	June 30, 2008	June 30, 2007
Net income (loss) available to common shareholders	$ (1,792)	$ 724
Adjustments:		
Unrealized (gains) losses on derivatives, net of tax	2,790	94
Gain on sale of investment, net of cash	—	(51)
Loss on conversion/exchange of preferred stock	43	—
Adjusted net income available to common shareholders*	1,041	767
Preferred stock dividends	20	52
Interest on 2.75% contingent convertible notes, net of tax	3	—
Total adjusted net income	$ 1,064	$ 819
Weighted average fully diluted shares outstanding**	541	515
Adjusted earnings per share assuming dilution*	$ 1.97	$ 1.59

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

(a) Management uses adjusted net income available to common to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
(b) Adjusted net income available to common is more comparable to earnings estimates provided by securities analysts.
(c) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

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

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

SIX MONTHS ENDED:	June 30, 2008	June 30, 2007
EBITDA	$ (1,533)	$ 2,325
Adjustments, before tax:		
Unrealized (gains) losses on natural gas and oil derivatives	4,538	158
Gain on sale of investment	—	(83)
Adjusted ebitda*	$ 3,005	$ 2,400

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

(a) Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
(b) Adjusted ebitda is more comparable to estimates provided by securities analysts.
(c) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF July 31, 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.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF JULY 16, 2008
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF JULY 31, 2008

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 16, 2008, we are using the following key assumptions in our projections for the full years 2008, 2009 and 2010.

The primary changes from our May 1, 2008 Outlook are in ***italicized bold*** and are explained as follows:

1) Production guidance has been updated for full years 2009 and 2010;
2) Certain budgeted capital expenditure assumptions and cash flow sources have been updated; and
3) Shares outstanding have been updated to reflect our recent common stock offering and to incorporate the effects of certain contingent convertible senior notes.

The company will provide its traditional full hedging update disclosure with its 2008 second quarter earnings release.

	Year Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production[(a)]			
Natural gas – bcf	791 – 801	***943 – 963***	***1,122 – 1,162***
Oil – mbbls	11,000	12,000	13,000
Natural gas equivalent – bcfe	857 – 867	***1,015 – 1,035***	***1,200 –1,240***
Daily natural gas equivalent midpoint – mmcfe	2,360	***2,810***	***3,340***
Year-over-year production increase	21%	***19%***	***19%***
NYMEX Prices[(b)] *(for calculation of realized hedging effects only):*			
Natural gas - $/mcf	$8.14	$8.00	$8.00
Oil - $/bbl	$84.48	$80.00	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	$1.17	$0.93	$0.40
Oil - $/bbl	$(7.47)	$1.78	$4.34
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	10 – 14%	10 – 14%	10 – 14%
Oil - $/bbl	7 – 9%	7 – 9%	7 – 9%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.95 – 1.05	$1.00 – 1.10	$1.05 – 1.15
Production taxes (~ 5% of O&G revenues)[(c)]	$0.35 – 0.40	$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 – 0.12	$0.10 – 0.12	$0.10 – 0.12
DD&A of natural gas and oil assets	$2.50 – 2.70	$2.50 – 2.70	$2.50 – 2.70
Depreciation of other assets	$0.20 – 0.24	$0.20 – 0.24	$0.20 – 0.24
Interest expense[(e)]	$0.50 – 0.55	$0.50 – 0.55	$0.50 – 0.55
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	***530***	***563***	***574***
Diluted	***566***	***601***	***609***

Cash Flow Projections – in millions	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]	***$5,500 – 5,600***	***$6,800 – 7,200***	***$8,300 – 9,500***
Sale of leasehold and producing properties[a]	***$8,000 – 8,500***	***$3,000 – 4,000***	***$3,000 – 4,000***
Debt and equity offerings	***$4,600***	-	-
Proceeds from investments and other	***$500***	***$600***	***$700***
Total Cash Inflows	***$18,600 – 19,200***	***$10,400 – 11,800***	***$12,000 – 14,200***
Outflows:			
Drilling	($5,500 – 6,000)	***($6,000 – 6,500)***	***($6,300 – 6,800)***
Acquisition of leasehold and producing properties	***($7,000 – 8,000)***	***($2,000 – 2,300)***	***($2,000 – 2,300)***
Geophysical costs	($300)	($300)	($300)
Midstream, compression and other PP&E	***($1,700 – 2,300)***	***($1,000 – 1,300)***	***($1,000 – 1,300)***
Dividends, Sr. Notes redemption, capitalized interest, etc.	***($1,100)***	***($600)***	***($600)***
Total Cash Outflows	***($15,600 – 17,700)***	***($9,900 – 11,000)***	***($10,200 – 11,300)***
Net Cash Change	***$900 – $3,600***	***($600) – $1,900***	***$700 – $4,000***

(a) The 2008 forecast reflects both completed and anticipated sales by the company of: 1) producing properties for $625 million in the 2008 second 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 $1.50 - 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 March 2008 and NYMEX natural gas prices have been updated for actual contract prices through April 2008.

(c) Severance tax per mcfe is based on NYMEX prices of $84.48 per bbl of oil and $7.60 to $8.90 per mcf of natural gas during 2008; and $80.00 per bbl of oil and $7.80 to $9.10 per mcf of natural gas during 2009 and 2010.

(d) Excludes expenses associated with non-cash 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.