



News Release

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**FOR IMMEDIATE RELEASE
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**CHESAPEAKE ENERGY CORPORATION REPORTS RECORD RESULTS
FOR THE FOURTH QUARTER AND FULL-YEAR 2004**

Company Reports 2004 Fourth Quarter Net Income Available to Common Shareholders of \$163 Million on Revenue of \$942 Million and Production of 103 Bcfe

Company Reports Full-Year 2004 Net Income Available to Common Shareholders of \$439 Million on Revenue of \$2,709 Million and Production of 363 Bcfe

Proved Reserves Reach 4.9 Tcfe from Proved Reserve Adds of 1.7 Tcfe; Reserve Replacement Equals 578% at the Attractive Drilling and Acquisition Cost of \$1.21 Per Mcfe; Proved Reserves Now Expected to Exceed 5.4 Tcfe by Year-End 2005 and 5.8 Tcfe by Year-End 2006

Oil and Natural Gas Production Increases 40% Quarter-over-Quarter, 35% Year-over-Year, and 9% Sequential Quarter-over-Quarter; Organic Growth in 2004 Reaches 20%, Exceeds 2003's Excellent Organic Growth Rate of 18%; Chesapeake Now 4th Largest Independent Producer of U.S. Natural Gas

OKLAHOMA CITY, OKLAHOMA, FEBRUARY 22, 2005 – Chesapeake Energy Corporation (NYSE: CHK) today reported financial and operating results for the fourth quarter of 2004 and for the full-year 2004. For the quarter, Chesapeake generated net income available to common shareholders of \$163.2 million (\$0.52 per fully diluted common share), operating cash flow of \$423.7 million (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of \$550.1 million (defined as income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of \$942.1 million and production of 102.9 billion cubic feet of natural gas equivalent (bcfe).

For the full-year 2004, Chesapeake generated net income available to common shareholders of \$439.0 million (\$1.53 per fully diluted common share), operating cash flow of \$1,418.8 million and ebitda of \$1,583.6 million on revenue of \$2,709.3 million and production of 362.6 bcfe.

The company's fourth quarter and full-year 2004 net income available to common shareholders and ebitda include various items that are typically not included in published estimates of the company's financial results by certain securities analysts. Such items and their after-tax effects on fourth quarter and full-year reported results are described as follows:

- an unrealized mark-to-market gain of \$69.2 million for the fourth quarter and a \$22.8 million gain for the full year resulting from the company's oil and natural gas and interest rate hedging programs;
- an \$11.3 million loss for the fourth quarter and a \$15.7 million loss for the full year resulting from the early extinguishment of certain Chesapeake debt securities;
- a \$2.9 million loss for the fourth quarter and for the full year related to the settlement of certain litigation; and
- an adjustment to net income available to common shareholders of \$36.7 million representing a loss on the retirement of preferred stock related to the exchange of substantially all of our 6.0% convertible preferred stock for common stock in the fourth quarter.

Adjusted for the above-mentioned gains and losses and giving effect to the issuance of common shares for preferred shares, Chesapeake's net income to common shareholders in the fourth quarter of 2004 would have been \$153.5 million (\$0.44 per fully diluted common share) and ebitda would have been \$464.7 million. Similarly adjusted, Chesapeake's net income to common shareholders for the full year 2004 would have been \$511.0 million (\$1.56 per fully diluted common share) and ebitda would have been \$1,571.7 million. The foregoing items do not affect the calculation of operating cash flow. A reconciliation of operating cash flow, ebitda and adjusted net income to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 15-17 of this release.

**Oil and Natural Gas Production Again Sets Record; Fourth Quarter 2004
Production Up 40% Over Fourth Quarter 2003; Full-Year 2004 Production
35% Higher than Full-Year 2003 Production; Sequential Organic
Growth Rate 8% in Fourth Quarter 2004 and 20% in Full-Year 2004**

Production for the 2004 fourth quarter was 102.9 bcfe, an increase of 29.6 bcfe, or 40%, over the 73.3 bcfe produced in the 2003 fourth quarter and an increase of 8.7 bcfe, or 9%, over the 94.2 bcfe produced in the 2004 third quarter. The 29.6 bcfe increase in 2004's fourth quarter production over 2003's fourth quarter production consisted of 14.4 bcfe (49%) generated from organic drillbit growth and 15.2 bcfe (51%) generated from

acquisitions. The 8.7 bcfe increase in sequential quarterly production consisted of 6.7 bcfe (77%) generated from organic drillbit growth and 2.0 bcfe (23%) generated from acquisitions. The company's 2004 fourth quarter production exceeded its December 27, 2004 forecasted 2004 fourth quarter mid-point production by 4.4 bcfe, or 4.5%, because of stronger than expected drilling and operational results.

Production for the full-year 2004 was 362.6 bcfe, an increase of 94.2 bcfe, or 35%, over the 268.4 bcfe produced in 2003 and an increase of 181.1 bcfe, or 100%, over the 181.5 bcfe produced in 2002. The 94.2 bcfe increase in 2004's production over 2003's production consisted of 52.2 bcfe (55%) generated from organic drillbit growth and 42.0 bcfe (45%) generated from acquisitions.

Chesapeake's 2004 organic growth rate of 20% follows organic growth of 18% in 2003, 6% in 2002 and 9% in 2001. During these four years, Chesapeake's total organic growth rate has been 69% and its average annual organic growth rate has been 14%. Total company production growth was 35% in 2004, 48% in 2003, 19% in 2002 and 25% in 2001 (U.S. only). Chesapeake is projecting total company production growth rates of 20% in 2005 and 11% in 2006 and organic growth rates of 10% in 2005 and 10% in 2006.

Chesapeake's 2004 fourth quarter production of 102.9 bcfe was comprised of 92.2 billion cubic feet of natural gas (bcf) (90% on a natural gas equivalent basis) and 1.79 million barrels of oil and natural gas liquids (mmbo) (10% on a natural gas equivalent basis). Chesapeake's average daily production rate for the quarter was 1,119 million cubic feet of natural gas equivalent production (mmcfe), consisting of 1,002 mmcf of gas and 19,478 barrels of oil and natural gas liquids. The 2004 fourth quarter was Chesapeake's 14th consecutive quarter of sequential production growth. During these 14 quarters, Chesapeake's U.S. production has increased 186%, for an average compound quarterly growth rate of 7.8% and an average compound annual growth rate of 34.6%.

Production for the full-year 2004 of 362.6 bcfe was comprised of 322.0 bcf (89% on a natural gas equivalent basis) and 6.76 mmbo (11% on a natural gas equivalent basis). Chesapeake's average daily production rate for the year was 991 mmcfe, consisting of 880 mmcf of gas and 18,481 barrels of oil and natural gas liquids. The full-year 2004 was Chesapeake's 15th consecutive year of sequential production growth. During these 15 years, Chesapeake's production has increased at an average compound annual growth rate of 74%.

**Oil and Natural Gas Proved Reserves Reach Record Level of 4.9 Tcfe;
Drilling and Acquisition Costs are \$1.21 per Mcfe as Company
Adds 2.1 Tcfe; Reserve Replacement Reaches 578%**

Chesapeake began 2004 with estimated proved reserves of 3,169 bcfe and ended the year with 4,902 bcfe, an increase of 1,733 bcfe, or 55%. During 2004, the company replaced its 363 bcfe of production with an estimated 2,096 bcfe of new proved

reserves, for a reserve replacement rate of 578% at a drilling and acquisition cost of \$1.21 per thousand cubic feet of natural gas equivalent (mcf). Reserve replacement through the drillbit was 962 bcfe, or 265% of production (including 141 bcfe from performance revisions and 5 bcfe from oil and natural gas price increases), or 46% of the total increase, at a cost of \$1.03 per mcfe. Reserve replacement through acquisitions (reduced for 4 bcfe sold during the year) was 1,134 bcfe, or 313% of production, or 54% of the total increase, at a cost of \$1.36 per mcfe.

Total costs incurred, including drilling, completion, acquisition, seismic, leasehold, capitalized internal costs, non-cash tax basis step-up from corporate acquisitions (\$464 million in 2004, or \$0.22 per mcfe, frequently booked as goodwill in the industry), asset retirement obligations and all other miscellaneous costs capitalized to our oil and natural gas properties were \$1.80 per mcfe. These costs exclude future development costs of proved undeveloped reserves. A complete reconciliation of finding and acquisition cost information and a roll forward of proved reserves is presented on page 13 of this release.

Of the company's estimated proved reserves at year-end 2004, 66% were proved developed compared to 74% in 2003, 74% in 2002 and 71% in 2001. Seventy-five percent of this year's estimated proved reserves are covered by reports prepared by independent third-party reservoir engineers (as opposed to reviews or audits of internally prepared estimates), compared to 74% in 2003, 73% in 2002 and 71% in 2001.

As of December 31, 2004, the company's estimated future net cash flows discounted at 10% before taxes (PV-10) from its proved reserves were \$10.5 billion using field differential adjusted prices of \$39.91 per bo (based on a NYMEX year-end price of \$43.39 per bo) and \$5.65 per mcf (based on a NYMEX year-end price of \$6.18 per mcf). In addition to the PV-10 value of proved reserves, the company believes that its drilling rig investments are worth \$175 million, its midstream gas gathering and compression assets are worth \$100 million, and its 4,000 bcfe of non-proved reserves are worth \$1.0-2.0 billion.

Last year's PV-10 of its proved reserves was \$7.3 billion using field differential adjusted prices of \$30.22 per bo (based on a NYMEX year-end price of \$32.47 per bo) and \$5.68 per mcf (based on a NYMEX year-end price of \$5.97 per mcf). Chesapeake's PV-10 changes by approximately \$215 million for every \$0.10 per mcf change in gas prices and approximately \$40 million for every \$1.00 per bo change in oil prices. The company's proved developed producing reserves decline rate is projected to be 26% in the first year (2005), 18% in year two, 14% in year three, 12% in year four and 11% in year five.

Average Prices Realized and Hedging Results and Hedging Positions Detailed

Average prices realized during the 2004 fourth quarter (including realized gains or losses from oil and gas derivatives, but excluding unrealized gains or losses on such

derivatives) were \$28.70 per bo and \$5.50 per mcf, for a realized gas equivalent price of \$5.42 per mcf. Chesapeake's average realized pricing differentials to NYMEX during the fourth quarter were a negative \$3.20 per bo and a negative \$1.19 per mcf. Realized gains or losses from oil and natural gas hedging activities during the quarter generated a \$15.40 loss per bo and a \$0.65 loss per mcf, for a 2004 fourth quarter realized hedging loss of \$87.3 million, or \$0.85 per mcf.

Average prices realized during the full-year 2004 (including realized gains or losses from oil and gas derivatives, but excluding unrealized gains or losses on such derivatives) were \$28.33 per bo and \$5.29 per mcf, for a realized gas equivalent price of \$5.23 per mcf. Chesapeake's average realized pricing differentials to NYMEX during 2004 were a negative \$2.35 per bo and a negative \$0.77 per mcf. Realized gains or losses from oil and natural gas hedging activities during the year generated a \$10.24 loss per bo and a \$0.27 loss per mcf, for a full-year 2004 realized hedging loss of \$154.9 million, or \$0.43 per mcf. This compares to oil and gas hedging gains of \$184.0 million realized from 2001-03.

In the past two months, Chesapeake has added to its hedge positions in 2005 and 2006. The following tables compare Chesapeake's projected 2005-06 oil and natural gas production volumes that have been hedged as of February 22, 2005 to what had been previously hedged as of December 27, 2004.

Hedged Positions as of February 22, 2005

Quarter or Year	Oil		Natural Gas	
	% Hedged	\$ NYMEX	% Hedged	\$ NYMEX
2005 1Q	53%	\$41.87	68%	\$6.82
2005 2Q	61%	\$42.39	54%	\$5.98
2005 3Q	15%	\$38.00	46%	\$5.96
2005 4Q	9%	\$32.15	26%	\$5.87
2005 Total	34%	\$41.02	48%	\$6.24
2006	-	-	9%	\$6.15

Hedged Positions as of December 27, 2004

Quarter or Year	Oil		Natural Gas	
	% Hedged	\$ NYMEX	% Hedged	\$ NYMEX
2005 1Q	52%	\$41.76	67%	\$6.80
2005 2Q	52%	\$41.63	39%	\$5.78
2005 3Q	8%	\$31.16	34%	\$5.75
2005 4Q	8%	\$30.62	23%	\$5.74
2005 Total	30%	\$40.20	40%	\$6.17
2006	-	-	9%	\$6.15

Depending on changes in oil and natural gas futures markets and management's view of underlying oil and natural gas supply and demand trends, Chesapeake may either increase or decrease its hedging positions at any time in the future without notice.

The company's initial 2005 first quarter forecast and updated 2005 and 2006 forecasts are attached to this release in an Outlook dated February 22, 2005 labeled as Schedule "A". This Outlook has been changed from the Outlook dated December 27, 2004 (attached as Schedule "B" for investors' convenience) to reflect various updated information.

Key Operational and Financial Statistics are Summarized Below for the 2004 Fourth Quarter and the Full-Year 2004

The table below summarizes Chesapeake's key results during the 2004 fourth quarter and compares them to the 2004 third quarter and the 2003 fourth quarter:

	<u>Three Months Ended:</u>		
	<u>12/31/04</u>	<u>9/30/04</u>	<u>12/31/03</u>
Average daily production (in mmcfe)	1,119	1,024	797
Gas as % of total production	90	88	90
Natural gas production (in bcf)	92.2	83.2	66.3
Average realized gas price (\$/mcf) (a)	5.50	5.17	5.15
Oil production (in mbbbls)	1,792	1,834	1,165
Average realized oil price (\$/bo) (a)	28.70	29.15	23.76
Natural gas equivalent production (in bcfe)	102.9	94.2	73.3
Gas equivalent realized price (\$/mcfe) (a)	5.42	5.13	5.03
Net marketing income (\$/mcfe)	.07	.04	.04
General and administrative costs (\$/mcfe) (b)	(.08)	(.09)	(.10)
Production taxes (\$/mcfe)	(.34)	(.33)	(.28)
Production expenses (\$/mcfe)	(.55)	(.57)	(.49)
Interest expense (\$/mcfe) (a)	(.43)	(.45)	(.51)
DD&A of oil and gas properties (\$/mcfe)	(1.67)	(1.63)	(1.41)
D & A of other assets (\$/mcfe)	(.09)	(.08)	(.06)
Operating cash flow (\$ in millions) (c)	423.7	353.4	262.4
Operating cash flow (\$/mcfe)	4.12	3.75	3.58
Ebitda (\$ in millions) (d)	550.1	361.3	257.8
Ebitda (\$/mcfe)	5.34	3.83	3.52
Net income to common shareholders (\$ in millions)	163.2	85.6	62.4

(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 non-cash stock-based compensation

(c) defined as cash flow provided by operating activities before changes in assets and liabilities

(d) defined as income before income taxes, interest expense, and depreciation, depletion and amortization expense

In addition, the table below summarizes Chesapeake's key statistics during 2004 and compares them to the prior two years' results:

	<u>Year Ended:</u>		
	<u>12/31/04</u>	<u>12/31/03</u>	<u>12/31/02</u>
Average daily production (in mmcfe)	991	735	497
Gas as % of total production	89	90	89
Natural gas production (in bcf)	322.0	240.4	160.7
Average realized gas price (\$/mcf) (a)	5.29	4.85	3.54
Oil production (in mbbls)	6,764	4,665	3,466
Average realized oil price (\$/bbl) (a)	28.33	25.85	25.22
Natural gas equivalent production (in bcfe)	362.6	268.4	181.5
Gas equivalent realized price (\$/mcfe) (a)	5.23	4.79	3.61
Net marketing income (\$/mcfe)	.05	.04	.03
General and administrative costs (\$/mcfe) (b)	(.09)	(.08)	(.10)
Production taxes (\$/mcfe)	(.29)	(.29)	(.17)
Lease operating expenses (\$/mcfe)	(.56)	(.51)	(.54)
Interest expense (\$/mcfe) (a)	(.45)	(.55)	(.61)
DD&A of oil and gas properties (\$/mcfe)	(1.61)	(1.38)	(1.22)
D & A of other assets (\$/mcfe)	(.08)	(.06)	(.08)
Operating cash flow (\$ in millions) (c)	1,418.8	903.9	412.5
Operating cash flow (\$/mcfe)	3.91	3.37	2.27
Ebitda (\$ in millions) (d)	1,583.6	1,041.6	414.4
Ebitda (\$/mcfe)	4.37	3.88	2.28
Net income to common shareholders (\$ in millions)	439.0	290.5	30.2

(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 non-cash stock based compensation

(c) defined as cash flow provided by operating activities before changes in assets and liabilities

(d) defined as income before income taxes and cumulative effect of accounting change, interest expense, and depreciation, depletion and amortization expense

Company's Leasehold and 3-D Seismic Inventories Now Exceed 3.3 Million and 9.9 Million Net Acres; Identified Non-Proved Reserves in Company's Extensive Gas Resource Plays Exceed 4.0 Tcfe

Chesapeake's exploratory and development drilling programs and production enhancement operations on its existing and acquired properties continue to produce operational results that exceed the company's forecasts and distinguish the company among its peers. During 2004, Chesapeake drilled 561 gross (425 net) operated wells and participated in another 890 gross (121 net) wells operated by other companies. The company's drilling success rate was 96% for company-operated wells and 96% for non-operated wells. During the year, Chesapeake invested \$756 million in operated wells (using an average of 56 operated rigs during 2004), \$236 million in non-operated wells (using an average of approximately 65 non-operated rigs during 2004) and \$300 million in acquiring new 3-D seismic data and new leases (exclusive of leases acquired through acquisitions).

The key to Chesapeake's strong organic growth rates during 2004 and in the past four years was our early recognition that oil and gas prices were undergoing structural change. We subsequently reacted by investing more than \$1.3 billion in new leasehold

and 3-D seismic acquisitions. In addition, during the past four years, we have significantly strengthened our technical capabilities by tripling our land, geoscience and engineering staff to more than 400 employees.

In addition to making significant additions to our existing core leasehold positions in the Anadarko and Arkoma Basins, South Texas, Texas Gulf Coast and Permian Basin projects, Chesapeake has also been aggressively building significant leasehold positions in the following gas resource plays: Sahara in the northwestern Anadarko Basin (approximately 600,000 prospective net acres acquired to date), the Mountain Front Deep Springer play in the western and southern Anadarko Basin (approximately 100,000 prospective net acres acquired to date), the Granite Wash and Cherokee/Atoka Wash plays in the western Anadarko Basin (approximately 200,000 prospective net acres acquired to date), the Hartshorne Coal and the Caney, Woodford and Fayetteville Shale plays of the Arkoma Basin (approximately 250,000 prospective acres acquired to date), the Barnett Shale play in North Texas (approximately 30,000 prospective net acres acquired to date, mainly in northern Johnson County), the Cotton Valley play in Northern Louisiana's Sligo Field (25,000 prospective net acres acquired to date) and, most recently, the Haley Deep play in West Texas (approximately 100,000 prospective net acres acquired to date).

Chesapeake believes it has built the largest onshore U.S. inventories of leasehold and 3-D seismic in the industry (more than 3.3 million and 9.9 million net acres, respectively) and believes it has identified more than a seven-year drilling backlog of 7,000 locations on which the company expects to develop more than 4.0 trillion cubic feet of natural gas equivalent (tcfe) of internally estimated non-proved reserves.

Balance Sheet Continues to Strengthen in 2004

As of December 31, 2004, Chesapeake's long-term debt was \$3.1 billion and its stockholders' equity was \$3.2 billion, for a debt-to-total capitalization ratio of 49%, compared to a debt-to-total capitalization ratio of 54% at year-end 2003. At year-end 2004, the company's estimated proved reserves were 4.9 tcfe, for long-term debt per mcfe of proved reserves of \$0.63, compared to \$0.65 per mcfe at year-end 2003. Pro forma for the BRG acquisition that closed on February 1, 2005, Chesapeake's estimated proved reserves were 5.1 tcfe. Given Chesapeake's strong reserve replacement record through the drillbit, low operating costs and high returns on invested capital, the company believes that it will continue to strengthen its balance sheet in the years ahead.

In late January 2005, Chesapeake increased its financial flexibility by amending its secured revolving bank credit facility to expand the borrowing base and amount available to \$1.25 billion and to extend the maturity to January 2010.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "Today's announcement of very strong operational and financial results for the fourth quarter and full-year 2004 provides compelling evidence that Chesapeake's business strategy continues to create significant shareholder value. Key measures reflecting this increase in shareholder value are:

- a record level of proved reserves, production, net income to common shareholders, cash flow and ebitda;
- exceptional organic growth for the 2004 fourth quarter and the full-year 2004, organic growth that we believe is the best performance among all public mid- and large-cap E&P companies;
- a 9% increase in sequential quarterly production in the 2004 fourth quarter compared to the 2004 third quarter;
- a 40% increase in year-over-year fourth quarter production;
- a 35% increase in full-year 2004 production over 2003 production;
- a 20% increase in estimated 2005 production over 2004 production;
- an 11% increase in estimated 2006 production over estimated 2005 production;
- reserve replacement for the year of 578% at a drilling and acquisition cost of \$1.21 per mcfe;
- excellent operating cost control and high returns on equity and total capital; and
- a seven-year inventory of drilling projects with estimated development potential of at least 4.0 tcf of estimated non-proved reserves in the years ahead.

The company's business strategy has worked very well for our shareholders since our IPO on February 4, 1993, generating an approximate 1,400% increase in our common stock price during the past 12 years. Our business strategy features delivering growth through a balance of acquisitions and organic drilling, focusing on natural gas to take advantage of strong long-term natural gas supply/demand fundamentals and building dominant regional scale to achieve low operating costs and high returns on capital. We believe Chesapeake's management team can continue the successful execution of the company's distinctive business strategy and continue to deliver significant shareholder value for years to come."

Conference Call Information

A conference call has been scheduled for Wednesday morning, February 23, 2005 at 9:00 a.m. EST to discuss this earnings release. The telephone number to access the conference call is 913.981.5520. For those unable to participate in the conference call, a replay will be available from 12:00 p.m. EST, February 23, 2005 through midnight EST on March 8, 2005. The number to access the conference call replay is 719.457.0820 and the passcode is 9640052. The conference call will also be simulcast live on the Internet and can be accessed at www.chkenergy.com by selecting "Conference Calls" under the

“Investor Relations” section. The webcast of the conference call will be available on the 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 oil and gas reserves, expected oil and gas production and future expenses, projections of future oil and gas prices, planned capital expenditures for drilling, leasehold acquisitions and seismic data, and statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning 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.

Factors that could cause actual results to differ materially from expected results are described under “Risk Factors” in our exchange offer prospectus dated November 30, 2004 (as amended on December 16, 2004) filed with the Securities and Exchange Commission on December 20, 2004. They include the volatility of oil and gas prices; adverse effects our substantial indebtedness and preferred stock obligations could have on our operations and future growth; our ability to compete effectively against strong independent oil and gas companies and majors; possible financial losses and significant collateral requirements as a result of our commodity price and interest rate risk management activities; uncertainties inherent in estimating quantities of oil and gas reserves, including reserves we acquire; projecting future rates of production and the timing of development expenditures; exposure to potential liabilities of acquired properties and companies; our ability to replace reserves; the availability of capital; writedowns of oil and gas carrying values if commodity prices decline; environmental and other claims in excess of insured amounts resulting from drilling and production operations; and the loss of key personnel. We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

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 oil and gas 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 terms “probable” and “possible” reserves or other descriptions of 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 being actually realized by the company.

Chesapeake Energy Corporation is the fourth largest independent producer of natural gas in the U.S. Headquartered in Oklahoma City, the company’s operations are focused on exploratory and developmental drilling and producing property acquisitions in the Mid-Continent, Permian Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States. The company’s Internet address is www.chkenergy.com.

CHESAPEAKE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(\$ in 000's, except per share data)
(unaudited)

THREE MONTHS ENDED:	December 31, 2004		December 31, 2003	
	\$	\$/mcf	\$	\$/mcf
REVENUES:				
Oil and gas sales	665,782	6.47	345,697	4.72
Oil and gas marketing sales	<u>276,269</u>	<u>2.68</u>	<u>111,044</u>	<u>1.51</u>
Total Revenues	<u>942,051</u>	<u>9.15</u>	<u>456,741</u>	<u>6.23</u>
OPERATING COSTS:				
Production expenses	56,321	0.55	35,919	0.49
Production taxes	35,372	0.34	20,557	0.28
General and administrative expenses:				
General and administrative (excluding stock-based compensation)	8,270	0.08	7,068	0.09
Stock-based compensation	1,703	0.02	433	0.01
Oil and gas marketing expenses	269,109	2.61	108,224	1.48
Oil and gas depreciation, depletion, and amortization	171,900	1.67	103,334	1.41
Depreciation and amortization of other assets	9,030	0.09	4,146	0.06
Provision for legal settlements	<u>4,500</u>	<u>0.04</u>	<u>5,400</u>	<u>0.07</u>
Total Operating Costs	<u>556,205</u>	<u>5.40</u>	<u>285,081</u>	<u>3.89</u>
INCOME FROM OPERATIONS	<u>385,846</u>	<u>3.75</u>	<u>171,660</u>	<u>2.34</u>
OTHER INCOME (EXPENSE):				
Interest and other income	913	0.01	1,471	0.02
Interest expense	(43,288)	(0.42)	(38,465)	(0.52)
Loss on repurchases or exchanges of Chesapeake debt	(17,632)	(0.17)	(20,759)	(0.28)
Loss on investment in Seven Seas	—	—	(2,015)	(0.03)
Total Other Income (Expense)	<u>(60,007)</u>	<u>(0.58)</u>	<u>(59,768)</u>	<u>(0.81)</u>
Income Before Income Taxes	325,839	3.17	111,892	1.53
Income Tax Expense:				
Current	—	—	4,670	0.06
Deferred	<u>117,301</u>	<u>1.14</u>	<u>37,849</u>	<u>0.52</u>
Total Income Tax Expense	<u>117,301</u>	<u>1.14</u>	<u>42,519</u>	<u>0.58</u>
NET INCOME	<u>208,538</u>	<u>2.03</u>	<u>69,373</u>	<u>0.95</u>
Preferred stock dividends	(8,707)	(0.08)	(6,985)	(0.10)
Loss on conversion/exchange of preferred stock	<u>(36,678)</u>	<u>(0.36)</u>	<u>—</u>	<u>—</u>
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	<u>163,153</u>	<u>1.59</u>	<u>62,388</u>	<u>0.85</u>
EARNINGS PER COMMON SHARE:				
Basic	<u>\$ 0.59</u>		<u>\$ 0.29</u>	
Assuming dilution	<u>\$ 0.52</u>		<u>\$ 0.25</u>	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's):				
Basic	<u>277,410</u>		<u>216,571</u>	
Assuming dilution	<u>328,029</u>		<u>273,169</u>	

CHESAPEAKE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(\$ in 000's, except per share data)
(unaudited)

TWELVE MONTHS ENDED:	December 31, 2004		December 31, 2003	
	\$	\$/mcf	\$	\$/mcf
REVENUES:				
Oil and gas sales	1,936,176	5.34	1,296,822	4.83
Oil and gas marketing sales	<u>773,092</u>	<u>2.13</u>	<u>420,610</u>	<u>1.57</u>
Total Revenues	<u>2,709,268</u>	<u>7.47</u>	<u>1,717,432</u>	<u>6.40</u>
OPERATING COSTS:				
Production expenses	204,821	0.56	137,583	0.51
Production taxes	103,931	0.29	77,893	0.29
General and administrative expenses:				
General and administrative (excluding stock-based compensation)	32,217	0.09	22,808	0.09
Stock-based compensation	4,828	0.01	945	—
Oil and gas marketing expenses	755,314	2.08	410,288	1.53
Oil and gas depreciation, depletion, and amortization	582,137	1.61	369,465	1.38
Depreciation and amortization of other assets	29,185	0.08	16,793	0.06
Provision for legal settlements	<u>4,500</u>	<u>0.01</u>	<u>6,402</u>	<u>0.02</u>
Total Operating Costs	<u>1,716,933</u>	<u>4.73</u>	<u>1,042,177</u>	<u>3.88</u>
INCOME FROM OPERATIONS	<u>992,335</u>	<u>2.74</u>	<u>675,255</u>	<u>2.52</u>
OTHER INCOME (EXPENSE):				
Interest and other income	4,476	0.01	2,827	0.01
Interest expense	(167,328)	(0.46)	(154,356)	(0.57)
Loss on repurchases or exchanges of Chesapeake debt	(24,557)	(0.07)	(20,759)	(0.08)
Loss on investment in Seven Seas	—	—	(2,015)	(0.01)
Total Other Income (Expense)	<u>(187,409)</u>	<u>(0.52)</u>	<u>(174,303)</u>	<u>(0.65)</u>
Income Before Income Taxes and Cumulative Effect of Accounting Change	804,926	2.22	500,952	1.87
Income Tax Expense:				
Current	—	—	5,000	0.02
Deferred	<u>289,771</u>	<u>0.80</u>	<u>185,360</u>	<u>0.69</u>
Total Income Tax Expense	<u>289,771</u>	<u>0.80</u>	<u>190,360</u>	<u>0.71</u>
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX	<u>515,155</u>	<u>1.42</u>	<u>310,592</u>	<u>1.16</u>
Cumulative Effect of Accounting Change, Net of Income Tax of \$1,464,000	—	—	<u>2,389</u>	<u>0.01</u>
NET INCOME	515,155	1.42	312,981	1.17
Preferred stock dividends	(39,506)	(0.11)	(22,469)	(0.09)
Loss on conversion/exchange of preferred stock	<u>(36,678)</u>	<u>(0.10)</u>	—	—
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	<u>438,971</u>	<u>1.21</u>	<u>290,512</u>	<u>1.08</u>
EARNINGS PER COMMON SHARE:				
Basic				
Income Before Cumulative Effect of Accounting Change	\$ 1.73		\$ 1.36	
Cumulative Effect of Accounting Change	—		0.02	
Net Income	<u>\$ 1.73</u>		<u>\$ 1.38</u>	
Assuming dilution				
Income Before Cumulative Effect of Accounting Change	\$ 1.53		\$ 1.20	
Cumulative Effect of Accounting Change	—		0.01	
Net Income	<u>\$ 1.53</u>		<u>\$ 1.21</u>	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's):				
Basic	253,212		211,203	
Assuming dilution	<u>305,718</u>		<u>258,567</u>	

CHESAPEAKE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(in 000's)
(unaudited)

	December 31, 2004	December 31, 2003
Cash	\$ 6,896	\$ 40,581
Other current assets	<u>560,644</u>	<u>301,823</u>
TOTAL CURRENT ASSETS	<u>567,540</u>	<u>342,404</u>
Property and equipment (net)	7,444,384	4,133,117
Other assets	<u>232,585</u>	<u>96,770</u>
TOTAL ASSETS	<u>\$ 8,244,509</u>	<u>\$ 4,572,291</u>
Current liabilities	\$ 963,953	\$ 513,156
Long term debt	3,075,109	2,057,713
Asset retirement obligation	73,718	48,812
Long term liabilities	34,973	28,774
Deferred tax liability	<u>933,873</u>	<u>191,026</u>
TOTAL LIABILITIES	<u>5,081,626</u>	<u>2,839,481</u>
STOCKHOLDERS' EQUITY	<u>3,162,883</u>	<u>1,732,810</u>
TOTAL LIABILITIES & STOCKHOLDERS' EQUITY	<u>\$ 8,244,509</u>	<u>\$ 4,572,291</u>
COMMON SHARES OUTSTANDING	<u>311,869</u>	<u>216,784</u>

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2004 COSTS INCURRED
(\$ in 000's, except per unit amounts)
(unaudited)

	<u>Cost</u>	<u>Reserves (in mmcf)</u>	<u>\$ Per Unit</u>
Exploration and development costs (a)	\$ 991,903	962,246	1.03
Acquisition of proved properties	<u>1,541,920</u>	<u>1,137,463</u>	1.36
Subtotal	<u>2,533,823</u>	<u>2,099,709</u>	1.21
Acquisition of unproved properties	570,495	—	—
Divestitures	(12,048)	(3,940)	(3.06)
Leasehold acquisition costs	110,530	—	—
Geological and geophysical costs	<u>55,618</u>	<u>—</u>	<u>—</u>
Adjusted subtotal	<u>3,258,418</u>	<u>2,095,769</u>	1.55
Tax basis step-up	463,949	—	—
Asset retirement obligation and other	<u>41,924</u>	<u>—</u>	<u>—</u>
Total	<u>\$ 3,764,291</u>	<u>2,095,769</u>	1.80

(a) Reserves include revisions to previous estimates

CHESAPEAKE ENERGY CORPORATION
ROLLFORWARD OF RESERVES
(unaudited)

	Mmcf
Beginning balance, 12/31/03	3,168,575
Production	(362,593)
Acquisitions	1,137,463
Divestitures	(3,940)
Revisions-performance	140,568
Revisions-price	4,950
Extensions and discoveries	<u>816,728</u>
Ending balance, 12/31/04	<u>4,901,751</u>
Reserve replacement	2,095,769
Reserve replacement rate	578%

CHESAPEAKE ENERGY CORPORATION
SUPPLEMENTAL DATA – OIL & GAS SALES AND INTEREST EXPENSE

	<u>Three Months Ended</u>		<u>Twelve Months Ended</u>	
	<u>December 31,</u>		<u>December 31,</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
Oil and Gas Sales (\$ in thousands):				
Oil sales	\$ 79,033	\$ 30,819	\$ 260,915	\$ 132,630
Oil derivatives – realized gains (losses)	(27,595)	(3,134)	(69,267)	(12,058)
Oil derivatives – unrealized gains (losses)	<u>25,379</u>	<u>(8,447)</u>	<u>3,454</u>	<u>(9,440)</u>
Total oil sales	<u>\$ 76,817</u>	<u>\$ 19,238</u>	<u>\$ 195,102</u>	<u>\$ 111,132</u>
Gas sales	\$ 566,492	\$ 281,452	\$ 1,789,275	\$ 1,171,050
Gas derivatives – realized gains (losses)	(59,658)	59,697	(85,634)	(5,331)
Gas derivatives – unrealized gains (losses)	<u>82,131</u>	<u>(14,690)</u>	<u>37,433</u>	<u>19,971</u>
Total gas sales	<u>\$ 588,965</u>	<u>\$ 326,459</u>	<u>\$1,741,074</u>	<u>\$ 1,185,690</u>
Total oil and gas sales	<u>\$ 665,782</u>	<u>\$ 345,697</u>	<u>\$1,936,176</u>	<u>\$ 1,296,822</u>
Average Sales Price (excluding gains (losses) on derivatives):				
Oil (\$ per bbl)	\$ 44.10	\$ 26.45	\$ 38.57	\$ 28.43
Gas (\$ per mcf)	\$ 6.15	\$ 4.25	\$ 5.56	\$ 4.87
Gas equivalent (\$ per mcf)	\$ 6.27	\$ 4.26	\$ 5.65	\$ 4.86
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil (\$ per bbl)	\$ 28.70	\$ 23.76	\$ 28.33	\$ 25.85
Gas (\$ per mcf)	\$ 5.50	\$ 5.15	\$ 5.29	\$ 4.85
Gas equivalent (\$ per mcf)	\$ 5.42	\$ 5.03	\$ 5.23	\$ 4.79
Interest Expense (\$ in thousands):				
Interest	\$ (44,446)	\$ (38,665)	\$ (162,781)	\$ (151,676)
Derivatives – realized (gains) losses	607	1,406	791	3,859
Derivatives – unrealized (gains) losses	<u>551</u>	<u>(1,206)</u>	<u>(5,338)</u>	<u>(6,539)</u>
Total Interest Expense	<u>\$ (43,288)</u>	<u>\$ (38,465)</u>	<u>\$ (167,328)</u>	<u>\$ (154,356)</u>

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED CASH FLOW DATA
(in 000's)
(unaudited)

THREE MONTHS ENDED:	December 31, 2004	December 31, 2003
Cash provided by operating activities	\$ 410,349	\$ 292,085
Cash (used in) investing activities	(712,963)	(476,449)
Cash provided by financing activities	260,437	186,467
TWELVE MONTHS ENDED:	December 31, 2004	December 31, 2003
Cash provided by operating activities	\$1,448,555	\$ 945,602
Cash (used in) investing activities	(3,381,204)	(2,077,217)
Cash provided by financing activities	1,898,964	924,559

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF CERTAIN FINANCIAL MEASURES
(in 000's)
(unaudited)

THREE MONTHS ENDED:	December 31, 2004	December 31, 2003
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 410,349	\$ 292,085
Adjustments:		
Changes in assets and liabilities	<u>13,330</u>	<u>(29,647)</u>
OPERATING CASH FLOW*	<u>\$ 423,679</u>	<u>\$ 262,438</u>

*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 an oil and gas 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 oil and gas 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:	December 31, 2004	December 31, 2003
Net income	\$ 208,538	\$ 69,373
Income tax expense	117,301	42,519
Interest expense	43,288	38,465
Depreciation and amortization of other assets	9,030	4,146
Oil and gas depreciation, depletion and amortization	<u>171,900</u>	<u>103,334</u>
EBITDA**	<u>\$ 550,057</u>	<u>\$ 257,837</u>

**Ebitda represents net income (loss) before cumulative effect of accounting change, income tax expense (benefit), 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:	December 31, 2004	December 31, 2003
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 410,349	\$ 292,085
Changes in assets and liabilities	13,330	(29,647)
Interest expense	43,288	38,465
Unrealized gains (losses) on oil and gas derivatives	107,510	(23,137)
Other non-cash items	<u>(24,420)</u>	<u>(19,929)</u>
EBITDA	<u>\$ 550,057</u>	<u>\$ 257,837</u>

TWELVE MONTHS ENDED:	December 31, 2004	December 31, 2003
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 1,448,555	\$ 945,602
Adjustments:		
Changes in assets and liabilities	<u>(29,752)</u>	<u>(41,673)</u>
OPERATING CASH FLOW*	<u>\$ 1,418,803</u>	<u>\$ 903,929</u>

*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 an oil and gas 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 oil and gas 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.

TWELVE MONTHS ENDED:	December 31, 2004	December 31, 2003
Net income before cumulative effect of accounting change	\$ 515,155	\$ 310,592
Income tax expense	289,771	190,360
Interest expense	167,328	154,356
Depreciation and amortization of other assets	29,185	16,793
Oil and gas depreciation, depletion and amortization	<u>582,137</u>	<u>369,465</u>
EBITDA**	<u>\$ 1,583,576</u>	<u>\$ 1,041,566</u>

**Ebitda represents net income (loss) before cumulative effect of accounting change, income tax expense (benefit), 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:

TWELVE MONTHS ENDED:	December 31, 2004	December 31, 2003
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 1,448,555	\$ 945,602
Changes in assets and liabilities	(29,752)	(41,673)
Interest expense	167,328	154,356
Unrealized gains (losses) on oil and gas derivatives	40,887	10,531
Other non-cash items	<u>(43,442)</u>	<u>(27,250)</u>
EBITDA**	<u>\$ 1,583,576</u>	<u>\$ 1,041,566</u>

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EARNINGS & ADJUSTED EBITDA
(\$ In 000's, except per share amounts)

	Three Months Ended December 31, 2004	Twelve Months Ended December 31, 2004
Net income available to common shareholders	\$ 163,153	\$ 438,971
Adjustments:		
Preferred stock dividends	8,707	39,506
Loss on conversion/exchange of preferred stock**	<u>36,678</u>	<u>36,678</u>
Net income	\$ 208,538	\$ 515,155
Adjustments, net of tax:		
Unrealized (gains) losses on derivatives	(69,159)	(22,751)
Loss on repurchases or exchanges of debt	11,284	15,716
Provision for legal settlements	<u>2,880</u>	<u>2,880</u>
Adjusted earnings*	<u>\$ 153,543</u>	<u>\$ 511,000</u>
Adjusted earnings per share assuming dilution**	<u>\$ 0.44</u>	<u>\$ 1.56</u>
EBITDA	\$ 550,057	\$ 1,583,576
Adjustments, before tax:		
Unrealized (gains) losses on oil and gas derivatives	(107,510)	(40,887)
Loss on repurchases or exchanges of debt	17,632	24,557
Provision for legal settlements	<u>4,500</u>	<u>4,500</u>
Adjusted EBITDA*	<u>\$ 464,679</u>	<u>\$ 1,571,746</u>

*Adjusted earnings and adjusted earnings per share assuming dilution and adjusted EBITDA, non-GAAP financial measures, 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 and EBITDA because:

- a. Management uses adjusted earnings and adjusted EBITDA to evaluate the Company's operational trends and performance relative to other oil and gas producing companies.
- b. Adjusted earnings and adjusted EBITDA are more comparable to earnings and EBITDA 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.

**For purposes of calculating fully diluted shares and earnings per share assuming dilution for the fourth quarter and full-year 2004, accounting rules prohibit the company from assuming the conversion of the 6.0% preferred stock for common shares prior to conversion or exchange for either period since the effect would have been anti-dilutive. In determining adjusted earnings per share, we have reflected the converted shares as though they were converted at the beginning of the period (fully diluted share count of 347.8 million for the fourth quarter and 327.1 million for the full-year).

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF FEBRUARY 22, 2005

Quarter Ending March 31, 2005; Year Ending December 31, 2005; Year Ending December 31, 2006.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of February 22, 2005, we are using the following key assumptions in our projections for the first quarter of 2005, the full-year 2005 and the full-year 2006.

The primary changes from our December 27, 2004 Outlook are in italicized bold in the table and are explained as follows:

- 1) We have provided our first production forecast for the first quarter of 2005.
- 2) We have increased capital expenditures by \$100 million in 2005 and \$50 million in 2006 to reflect a planned increase in drilling activity on various company properties.
- 3) We have updated the projected effects from changes in our hedging positions since our December 27, 2004 Outlook.
- 4) We have included our expectations for future NYMEX oil and gas prices to illustrate hedging effects only.

	Quarter Ending <u>March 31,</u> <u>2005</u>	Year Ending <u>December 31,</u> <u>2005</u>	Year Ending <u>December 31,</u> <u>2006</u>
<i>Estimated Production:</i>			
Oil – Mbo	1,650	6,600	6,600
Gas – Bcf	91 – 92	391 – 399	438 – 448
Gas Equivalent - Bcfe	101 - 102	430 – 438	478 – 488
Daily gas equivalent midpoint –in Mmcf	1,128	1,190	1,325
<i>NYMEX Prices (for calculation of realized hedging effects only):</i>			
Oil - \$/Bo	\$42.28	\$40.57	\$40.00
Gas - \$/Mcf	\$6.17	\$6.04	\$6.00
<i>Estimated Differentials to NYMEX Prices:</i>			
Oil - \$/Bo	-\$2.75	-\$2.75	-\$2.75
Gas - \$/Mcf	-\$0.75	-\$0.70	-\$0.70
<i>Estimated Realized Hedging Effects (based on expected NYMEX prices above):</i>			
Oil - \$/Bo	-\$0.23	\$0.04	\$0.00
Gas - \$/Mcf	\$0.56	\$0.07	\$0.00
<i>Operating Costs per Mcfe of Projected Production:</i>			
Production expense	\$0.62 – 0.67	\$0.62 – 0.67	\$0.68 – 0.72
Production taxes (generally 7% of O&G revenues)	\$0.38 – 0.40	\$0.38 – 0.40	\$0.38 – 0.40
General and administrative	\$0.10 – 0.11	\$0.10 – 0.11	\$0.11 – 0.12
Stock-based compensation (non-cash)	\$0.02 – 0.04	\$0.04 – 0.06	\$0.09 – 0.10
DD&A – oil and gas	\$1.70 – 1.75	\$1.75 – 1.80	\$1.80 – 1.90
Depreciation of other assets	\$0.09 – 0.11	\$0.09 – 0.11	\$0.10 – 0.12
Interest expense ^(a)	\$0.43 – 0.47	\$0.43 – 0.47	\$0.43 – 0.47
<i>Other Income and Expense per Mcfe:</i>			
Marketing and other income	\$0.02 – 0.04	\$0.02 – 0.04	\$0.02 – 0.04
<i>Book Tax Rate</i>	36.5%	36.5%	36.5%
<i>Equivalent Shares Outstanding:</i>			
Basic	314 mm	315 mm	318 mm
Diluted	352 mm	352 mm	355 mm

Capital Expenditures:

Drilling, leasehold and seismic

**\$350 - \$375
mm**

**\$1,400 -
\$1,500 mm**

**\$1,500 -
\$1,600 mm**

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

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include:

- (i) For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, 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) 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.
- (iii) Basis protection swaps are arrangements that guarantee a price differential of oil or gas from a specified delivery point. 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.

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, as a result, lock in the gain or loss on the transaction.

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and natural gas prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to oil and gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and gas 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 non-qualifying 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 oil and gas 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 oil and natural gas sales.

The company currently has in place the following natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Gain (Loss) from Locked Swaps	Avg. NYMEX Price Including Open & Locked Positions	% Hedged	
					Assuming Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Gas Production
2005:						
1 st Qtr	62.2	\$7.00	-\$0.18	\$6.82	91.5	68%
2 nd Qtr	52.2	\$6.17	-\$0.19	\$5.98	97.0	54%
3 rd Qtr	46.4	\$6.19	-\$0.23	\$5.96	101.5	46%
4 th Qtr	27.5	\$6.26	-\$0.39	\$5.87	105.0	26%
Total 2005 ⁽¹⁾	188.3	\$6.46	-\$0.22	\$6.24	395.0	48%
Total 2006 ⁽¹⁾	39.3	\$6.77	-\$0.62	\$6.15	443.0	9%
Total 2007 ⁽²⁾	-	-	-	-	470.0	-
TOTALS						
2005-2007	227.6	\$6.51	-\$0.29	\$6.22	1,308.0	17%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$3.75 to \$5.50 covering 70.0 bcf in 2005 and \$3.75 to \$5.50 covering 28.4 bcf in 2006.

(2) Swaps covering 25.6 bcf have been locked for 2007. This will result in the recognition of \$11.6 million of losses in 2007 when the hedging arrangements settle.

Note: Not shown above are collars covering 4.4 bcf of production in 2005 at a weighted average floor and ceiling of \$3.10 and \$4.44, and call options covering 7.3 bcf of production in 2005 at a weighted average price of \$6.00.

The company has also entered into the following natural gas basis protection swaps:

	Volume in Bcf's	NYMEX less:	Assuming Gas Production in Bcf's of:	% Hedged
2005	188.6	0.26	392.0	48%
2006	130.1	0.32	440.0	30%
2007	126.5	0.28	470.0	27%
2008	118.6	0.27	495.0	24%
2009	86.6	0.29	520.0	17%
Totals	650.4	\$ 0.28	2,317.0	28%

* weighted average

The company has entered into the following crude oil hedging arrangements:

	Open Swaps in mbo's	Avg. NYMEX Strike Price	% Hedged	
			Assuming Oil Production in mbo's of:	Open Swap Positions as % of Total Estimated Production
Q1 – 2005	870.5	\$41.87	1,650	53%
Q2 – 2005	1,001.0	\$42.39	1,650	61%
Q3 – 2005	246.0	\$38.00	1,650	15%
Q4 – 2005	153.5	\$32.15	1,650	9%
Total 2005 ⁽¹⁾	2,271.0	\$41.02	6,600	34%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$26.00 to \$34.00 covering 1,996 mbo in 2005.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF DECEMBER 27, 2004 (PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF FEBRUARY 22, 2005

Quarter Ending December 31, 2004; Year Ending December 31, 2004; Year Ending December 31, 2005; Year Ending December 31, 2006.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of December 27, 2004, we are using the following key assumptions in our projections for the fourth quarter of 2004, the full-year 2004, the full-year 2005 and the full-year 2006.

We expect to record non-operating losses in Q4 2004 in connection with our pending cash tender offer for our \$209.8 million of 8.375% senior notes due 2008 and our pending offer to exchange our 6.0% convertible preferred stock for our common stock. If we purchase all of our 8.375% senior notes pursuant to the tender offer, we estimate that an after-tax loss on the early redemption of the notes of \$12 million will be recorded in Q4 2004 as an adjustment to net earnings. If all our 6.0% preferred stock is exchanged for common stock, we estimate that a loss on the early conversion of the preferred stock of approximately \$37 million will be reflected as an adjustment to net income available to common shareholders for the purpose of calculating basic earnings per share in Q4 2004.

The primary changes from our November 30, 2004 Outlook are in italicized bold in the table and are explained as follows:

- 1) We have updated our previous production forecasts for 2005 and 2006 to reflect increases in production of 35 mmcf per day in 2005 (excluding January) and 55 mmcf per day in 2006 as a result of the announced acquisition of BRG Petroleum Corporation. This increases our full-year 2005 production forecast by 2.8% to a mid-point of 1,190 mmcf per day and our 2006 production forecast by 4.3% to a mid-point of 1,325 mmcf per day.
- 2) We have increased capital expenditures by \$50 million in 2005 and \$100 million in 2006 to reflect planned increased drilling activity planned on the BRG and other company properties.
- 3) We have updated the projected effects from changes in our hedging positions since our November 30, 2004 Outlook.
- 4) We have included our expectations for future NYMEX oil and gas prices to illustrate hedging effects only.

	<u>Quarter Ending December 31, 2004</u>	<u>Year Ending December 31, 2004</u>	<u>Year Ending December 31, 2005</u>	<u>Year Ending December 31, 2006</u>
<i>Estimated Production:</i>				
Oil – Mbo	1,588	6,560	6,600	6,600
Gas – Bcf	88.5 – 89.5	317 – 319	391 – 399	438 – 448
Gas Equivalent - Bcfe	98 - 99	356 – 358	430 – 438	478 – 488
Daily gas equivalent midpoint –in Mmcf	1,069	975	1,190	1,325
<i>NYMEX Prices (for calculation of realized hedging effects only):</i>				
Oil - \$/Bo	\$46.67	\$41.00	\$40.00	\$40.00
Gas - \$/Mcf	\$6.60	\$6.01	\$6.00	\$6.00
<i>Estimated Differentials to NYMEX Prices:</i>				
Oil - \$/Bo	-\$2.75	-\$2.65	-\$2.75	-\$2.75
Gas - \$/Mcf	-\$0.75	-\$0.70	-\$0.70	-\$0.70

Estimated Realized Hedging Effects (based on expected NYMEX prices above):

Oil - \$/Bo	-\$15.85	-\$10.19	\$0.06	\$0.00
Gas - \$/Mcf	-\$0.53	-\$0.23	\$0.05	-\$0.01

Operating Costs per Mcfe of Projected Production:

Production expense	\$0.57 – 0.62	\$0.57 – 0.62	\$0.62 – 0.67	\$0.68 – 0.72
Production taxes (generally 7% of O&G revenues)	\$0.40 – 0.44	\$0.28 – 0.33	\$0.38 – 0.40	\$0.38 – 0.40
General and administrative	\$0.10 – 0.11	\$0.10 – 0.11	\$0.10 – 0.11	\$0.11 – 0.12
Stock based compensation (non-cash)	\$0.02 – 0.04	\$0.02 – 0.04	\$0.04 – 0.06	\$0.09 – 0.10
DD&A – oil and gas	\$1.65 – 1.70	\$1.60 – 1.65	\$1.75 – 1.80	\$1.80 – 1.90
Depreciation of other assets	\$0.08 – 0.10	\$0.08 – 0.10	\$0.09 – 0.11	\$0.10 – 0.12
Interest expense ^(a)	\$0.45 – 0.49	\$0.45 – 0.49	\$0.43 – 0.47	\$0.43 – 0.47
Other Income and Expense per Mcfe:				
Marketing and other income	\$0.02 – 0.04	\$0.02 – 0.04	\$0.02 – 0.04	\$0.02 – 0.04

<i>Book Tax Rate</i>	36%	36%	36%	36%
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Equivalent Shares Outstanding:

Basic	279 mm	254 mm	313 mm	316 mm
Diluted	347 mm	327 mm	351 mm	354 mm

Capital Expenditures:

Drilling, leasehold and seismic	\$300 - \$325 mm	\$1,100 - \$1,150 mm	\$1,300 - \$1,400 mm	\$1,450 - \$1,550 mm
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(a) Does not include gains or losses on interest rate derivatives (SFAS 133).

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include:

- (i) For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, 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) 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.
- (iii) Basis protection swaps are arrangements that guarantee a price differential of oil or gas from a specified delivery point. 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.

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, as a result, lock in the gain or loss on the transaction.

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and natural gas prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to oil and gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and gas 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 non-qualifying 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 oil and gas 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 oil and natural gas sales.

The company currently has in place the following natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Gain (Loss) from Locked Swaps	Avg. NYMEX Price Including Open & Locked Positions	% Hedged	
					Assuming Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Gas Production
2004:						
1 st Qtr	69.5	\$5.94	\$0.03	\$5.97	70.1	99%
2 nd Qtr	62.2	\$5.15	\$0.00	\$5.15	76.5	81%
3 rd Qtr ⁽¹⁾	70.7	\$5.49	-\$0.09	\$5.40	83.2	85%
4 th Qtr ⁽¹⁾	76.5	\$5.88	-\$0.11	\$5.77	89.0	86%
Total 2004	278.9	\$5.63	-\$0.05	\$5.58	318.8	88%
2005:						
1 st Qtr	62.4	\$6.91	-\$0.11	\$6.80	93.4	67%
2 nd Qtr	38.5	\$6.05	-\$0.27	\$5.78	97.5	39%
3 rd Qtr	34.5	\$6.06	-\$0.31	\$5.75	100.8	34%
4 th Qtr	23.5	\$6.20	-\$0.46	\$5.74	103.0	23%
Total 2005⁽¹⁾	158.9	\$6.41	-\$0.24	\$6.17	394.7	40%
Total 2006⁽¹⁾	39.3	\$6.77	-\$0.62	\$6.15	443.0	9%
Total 2007⁽²⁾	-	-	-	-	470.0	-
TOTALS						
2005-2007	198.2	\$6.48	-\$0.31	\$6.17	1,307.7	15%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$3.50 to \$5.25 covering 25.4 bcf in 2004, \$3.75 to \$5.50 covering 60.2 bcf in 2005 and \$3.75 to \$5.50 covering 28.4 bcf in 2006.

(2) Swaps covering 25.6 bcf have been locked for 2007. This will result in the recognition of \$11.6 million of losses in 2007 when the hedging arrangements settle.

Note: Not shown above are collars covering 1.1 bcf and 4.4 bcf of production in Q4 2004 and in 2005, respectively, at a weighted average floor and ceiling of \$3.10 and \$4.44. In addition, call options covering 10.2 bcf and 7.3 bcf of production in Q4 2004 and in 2005 at a weighted average price of \$6.31 and \$6.00 are not included in the table above.

The company has also entered into the following natural gas basis protection swaps:

	Volume in Bcf's	NYMEX less:	Assuming Gas Production in Bcf's of:	% Hedged
2004	157.4	0.17	318.8	49%
2005	188.6	0.26	394.7	48%
2006	130.1	0.32	443.0	29%
2007	126.5	0.28	470.0	27%
2008	118.6	0.27	495.0	24%
2009	86.6	0.29	520.0	17%
Totals	<u>807.8</u>	<u>\$ 0.26</u>	<u>2,641.5</u>	<u>31%</u>

* weighted average

The company has entered into the following crude oil hedging arrangements:

	Open Swaps in mbo's	Avg. NYMEX Strike Price	Assuming Oil Production in mbo's of:	% Hedged Open Swap Positions as % of Total Estimated Production
Q1 – 2004	1,270	\$28.58	1,465	87%
Q2 – 2004	1,540	\$30.00	1,673	92%
Q3 – 2004 ⁽¹⁾	1,519	\$30.32	1,834	83%
Q4 – 2004 ⁽¹⁾	1,518	\$30.10	1,588	96%
Total 2004 ⁽¹⁾	<u>5,847</u>	<u>\$29.80</u>	<u>6,560</u>	<u>89%</u>
Q1 – 2005	855	\$41.76	1,650	52%
Q2 – 2005	865	\$41.63	1,650	52%
Q3 – 2005	138	\$31.16	1,650	8%
Q4 – 2005	138	\$30.62	1,650	8%
Total 2005 ⁽¹⁾	<u>1,996</u>	<u>\$40.20</u>	<u>6,600</u>	<u>30%</u>

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$21.00 to \$26.00 covering 2,240 mbo in 2004 and knockout prices ranging from \$26.00 to \$34.00 covering 1,996 mbo in 2005.