NEWS RELEASE

Chesapeake Energy Corporation Reports Strong Operating and Financial Results for the 2005 Second Quarter, Announces Property Acquisitions, Provides Operational Update and Increases Production Forecasts for 2005 and 2006

Company Reports 2005 Second Quarter Net Income Available to Common Shareholders of $179 Million on Revenue of $1.05 Billion and Production of 113 Bcfe
Oil and Natural Gas Production Reaches 1,244 Mmcfe per Day, a 31% Increase Over 2004 Second Quarter and 7% Over 2005 First Quarter; 2005 Total Production Growth Expected to Exceed 25%, 2005 Organic Growth Expected to Exceed 10%
Proved Reserves Reach 5.9 Tcfe and Non-Proven Reserves Exceed 5.0 Tcfe; First Half 2005 Proved Reserve Adds Total 948 Bcfe; Reserve Replacement Equals 535% at Drilling and Acquisition Cost of $1.49 Per Mcfe
Company Acquires 294 Bcfe of Proved, Probable and Possible Reserves and 33 Mmcfe of Current Daily Production for $410 Million in Four Transactions With Private Companies

PRNewswire-FirstCall
OKLAHOMA CITY

Chesapeake Energy Corporation today reported financial and operating results for the second quarter of 2005. For the quarter, Chesapeake generated net income available to common shareholders of $179.2 million ($0.52 per fully diluted common share), operating cash flow of $513.3 million (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $580.2 million (defined as income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1,048.0 million and production of 113.2 billion cubic feet of natural gas equivalent (bcfe).

The company's 2005 second quarter net income available to common shareholders and ebitda include certain items that are not typically included in published estimates of the company's financial results by many securities analysts. Such items and their after-tax effects on second quarter reported results are described as follows:

* an unrealized mark-to-market gain of $53.4 million resulting from the company's oil, natural gas and interest rate hedging programs;

* a $43.4 million loss resulting from the early extinguishment of certain Chesapeake debt securities; and

* a reduction of net income available to common shareholders of $4.7 million resulting from a loss on the exchange of approximately $45 million of Chesapeake's 4.125% cumulative convertible preferred stock into 2.9 million shares of the company's common stock through an unsolicited transaction with a holder of the preferred stock.

Adjusted for the above-mentioned items, Chesapeake's net income to common shareholders in the 2005 second quarter would have been $173.9 million ($0.50 per fully diluted common share) and ebitda would have been $564.6 million. The foregoing items do not affect the calculation of operating cash flow. A reconciliation of operating cash flow, ebitda, adjusted ebitda and adjusted net income available to common 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 Sets Record for 16th Consecutive Quarter; 2005 Second Quarter Average Daily Production Increases 31% Over 2004 Second Quarter and 7% Over 2005 First Quarter

Daily production for the 2005 second quarter averaged 1,244 million cubic feet of natural gas equivalent (mmcfe), an increase of 293 mmcfe, or 30.8%, over the 951 mmcfe produced per day in the 2004 second quarter and an increase of 82 mmcfe, or 7.1%, over the 1,162 mmcfe produced per day in the 2005 first quarter. Of the 82 mmcfe daily increase in sequential quarterly production, 37% came from organic growth and 63% from acquisition growth, making the company's quarterly organic growth rate 2.7%, its year-to-date organic growth rate 5.1% and its annualized 2005 organic growth rate 10.2%. The company's 2005 second quarter production exceeded its May 2, 2005 forecasted mid-point production by 3.7 bcfe, or 3.4%, because of stronger than projected drilling and operational results.

Chesapeake's 2005 second quarter production of 113.2 bcfe was comprised of 101.1 billion cubic feet of natural gas (bcf) (89% on a natural gas equivalent basis) and 2.01 million barrels of oil and natural gas liquids (mmbo) (11% on a natural gas equivalent basis). Chesapeake's average daily production rate of 1,244 mmcfe consisted of 1,111 mmcf of gas and 22,110 barrels of oil and natural gas liquids.

The 2005 second quarter was Chesapeake's 16th consecutive quarter of production growth. During these 16 quarters, Chesapeake's U.S. production has increased 214%, for an average compound quarterly growth rate of 7.4% and an average compound annual growth rate of 33.1%.

Key Operational and Financial Statistics are Summarized Below for the 2005 Second and First Quarters and the 2004 Second Quarter

The table below summarizes Chesapeake's key results during the 2005 second quarter and compares them to results from the 2005 first quarter and the 2004 second quarter:

	Three Months Ended		
	6/30/05	3/31/05	6/30/04
Average daily production (in mmcfe)	1,244	1,162	951
Gas as % of total production	89	90	88
Natural gas production (in bcf)	101.1	94.1	76.5
Average realized gas price ($/mcf) (A)	5.95	6.20	4.87
Oil production (in mbbls)	2,012	1,746	1,673
Average realized oil price ($/bo) (A)	42.82	41.74	28.12

Natural gas equivalent production (in bcfe)	113.2	104.6	86.5
Gas equivalent realized price ($/mcfe) (A)	6.08	6.27	4.85
Net marketing income ($/mcfe)	.05	.07	.04
General and administrative costs ($/mcfe) (B)	(.08)	(.09)	(.09)
Stock-based compensation ($/mcfe)	(.02)	(.02)	(.00)
Production taxes ($/mcfe)	(.42)	(.34)	(.26)
Production expenses ($/mcfe)	(.64)	(.66)	(.57)
Interest expense ($/mcfe) (A)	(.48)	(.44)	(.44)
DD&A of oil and gas properties ($/mcfe)	(1.85)	(1.73)	(1.58)
D & A of other assets ($/mcfe)	(.10)	(.10)	(.08)
Operating cash flow ($ in millions) (C)	513.3	505.5	308.2
Operating cash flow ($/mcfe)	4.53	4.83	3.56
Ebitda ($ in millions) (D)	580.2	431.0	324.1
Ebitda ($/mcfe)	5.13	4.12	3.74
Net income to common shareholders ($ in millions)	179.2	119.5	85.8

(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

Chesapeake Announces $410 Million of Acquisitions in the Barnett Shale, East Texas and Permian Basin Areas; Acquires 294 Bcfe of Proved, Probable and Possible (3P) Reserves and 33 Mmcfe of Current Daily Production

Subsequent to the end of the 2005 second quarter, Chesapeake has acquired or has agreed to acquire $410 million of natural gas assets in transactions with four private companies. Through these transactions, the company will acquire 33 mmcfe per day of current production, 113 bcfe of proved reserves and 181 bcfe of probable and possible reserves. After allocating $15 million of the purchase prices to gas gathering and compression assets and after including $368 million of future development costs, Chesapeake's estimated all-in acquisition cost for the 294 bcfe of 3P reserves will be $2.60 per thousand cubic feet of natural gas equivalent (mcfe).

The largest of the four acquisitions is Chesapeake's recently closed purchase of Hallwood Energy III L.P.'s 56% working interest in the 30,000 gross acre Chesapeake/Hallwood South Block AMI in Johnson County, Texas. Chesapeake had previously acquired a 44% working interest in the AMI area through its acquisition of Oklahoma City-based publicly-held Canaan Energy Corporation in June 2002.

In the South Block transaction, Chesapeake anticipates acquiring an internally estimated 174 bcfe of 3P reserves and current net production of 14 mmcfe per day. The company has identified 160 horizontal drilling locations on the 30,000 gross acre South Block that it believes can be drilled at an average cost of approximately $2.5 million per well to develop average estimated ultimate reserves (EUR) of approximately 2.0 bcfe per well. The company currently has two rigs drilling on this South Block acreage. Including production from both the North and South Block acreage, Chesapeake's current Barnett Shale average daily production is approximately 50 mmcfe and should average at least 80 and 120 mmcfe per day by December 2005 and December 2006, respectively.

The South Block proved reserves have a reserves-to-production index of 7.9 years, are 100% gas, have current lease operating expenses of $0.20 per mcfe, have severance taxes of less than 1.0% of the wellhead revenue value and are 100% Chesapeake-operated. The property's very low lease operating expenses (approximately $0.55 per mcfe below the industry average) and unusually low severance taxes (approximately $0.50 below the standard 7.5% Texas severance tax rate at $7.00 per mcf because of severance tax exemptions applicable to certain types of newly drilled wells in Texas) create an approximate $1.05 per mcfe economic advantage over typical acquisitions of other Texas or Mid- Continent natural gas properties. The company has hedged 100% of its newly acquired Hallwood production volumes at an average NYMEX gas price of $8.53 per mmbtu through March 31, 2006, well above the gas price used to value the property.

By comparison, in December 2004 when Chesapeake acquired its North Block acreage for $277 million, Chesapeake acquired 25 mmcfe of daily production and 3P reserves of 280 bcfe. The company projected that its all-in finding costs to develop the 3P reserves would be $2.07 per mcfe and it hedged the first two years of production at an average price of $6.89 per mmbtu.

Subsequent to closing the North Block acquisition, Chesapeake has invested $35 million in the drilling of 21 wells and has received $21 million of operating cash flow from production of 4.8 bcfe. Current production and proved reserves have increased 36% and 24%, respectively, in just eight months. Finding costs have been $1.12 per mcfe since the date of acquisition. Average well costs have been $2.4 million and per well reserves have been 2.8 bcfe compared to the company's estimates at the time of acquisition of $2.2 million and 2.5 bcfe. Chesapeake currently has four rigs drilling on the North Block and believes that it has approximately 135 more horizontal wells to drill on the North Block.

In addition to the Hallwood South Block acquisition, Chesapeake has also recently acquired or agreed to acquire an additional $160 million of natural gas properties in the East Texas and Permian Basin regions in three transactions with three private companies. In these acquisitions, Chesapeake is acquiring 19 mmcfe per day of net production and 120 bcfe of 3P reserves. The proved reserves acquired in the three miscellaneous transactions have a reserves-to-production index of 10.2 years, are 99% gas, have current lease operating expenses of approximately $0.20 per mcfe and will be 98% Chesapeake- operated.

The company has initially financed its recent acquisition activity with funds drawn from its bank credit facility, but intends to permanently fund these acquisitions with a combination of equity and/or long-term senior unsecured notes issuance in the near future.

Average Prices Realized, Hedging Positions Updated and Production Forecasts

for Second Half 2005 and Full Year 2006 Increased

Average prices realized during the 2005 second quarter (including realized gains or losses from oil and gas derivatives, but excluding unrealized gains or losses on such derivatives) were $42.82 per bo and $5.95 per mcf, for a realized gas equivalent price of $6.08 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the second quarter were a negative $4.78 per bo and a negative $0.65 per mcf. Realized losses from oil and natural gas hedging activities during the quarter generated a $5.29 loss per bo and a $0.34 loss per mcf, for a 2005 second quarter realized hedging loss of $44.4 million, or $0.39 per mcfe. This compares to a 2005 first quarter realized hedging gain of $40.3 million, or $0.39 per mcfe, and a 2004 second quarter realized hedging loss of $55.3 million, or $0.64 per mcfe.

Chesapeake has added to its 2005, 2006 and 2007 oil and natural gas hedge positions previously provided on May 2, 2005. The following tables compare Chesapeake's hedged production volumes through swaps as of August 4, 2005 to those as of May 2, 2005:

Swap Positions as of August 4, 2005

	Oil		Natural Gas	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2005 3Q	46%	$51.41	67%	$6.46
2005 4Q	48%	$52.99	52%	$6.89
2005 Remaining	47%	$52.22	59%	$6.65
2006	37%	$56.75	27%	$7.23
2007	8%	$53.33	2%	$7.06

Swap Positions as of May 2, 2005

	Oil		Natural Gas	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2005 3Q	35%	$48.46	57%	$6.28
2005 4Q	30%	$48.46	38%	$6.46
2005 Remaining	32%	$48.46	47%	$6.35
2006	16%	$54.77	18%	$6.85
2007	5%	$50.79	---	---

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 updated 2005 and 2006 forecasts are attached to this release in an Outlook dated August 4, 2005 labeled as Schedule "A". This Outlook has been changed from the Outlook dated May 2, 2005 (attached as Schedule "B" for investors' convenience) to reflect updated information resulting from the company's operational performance during the second quarter exceeding forecasted results and from the Hallwood and three miscellaneous acquisitions announced today.

Production estimates for 2005 were increased by 2.4%, or 30 mmcfe per day, to estimated total production of 460 bcfe for the year, or a daily average of 1,260 mmcfe. Production estimates for 2006 were increased by 2.0%, or 28 mmcfe per day, to estimated total production of 516 bcfe for the year, or a daily average of 1,414 mmcfe per day. This marks the 21st time that Chesapeake has increased its production estimates during the past 16 quarters.

Oil and Natural Gas Proved Reserves Reach Record Level of 5.9 Tcfe;
First Half 2005 Drilling and Acquisition Costs are $1.49 per Mcfe
as Company Adds 948 Bcfe and Replaces Production by 535%

Chesapeake began 2005 with estimated proved reserves of 4.902 trillion cubic feet of natural gas equivalent (tcfe) and ended the second quarter with 5.850 tcfe, an increase of 948 bcfe, or 19%. During the 2005 first half, the company replaced its 218 bcfe of production with an estimated 1,166 bcfe of new proved reserves, for a reserve replacement rate of 535% at a drilling and acquisition cost of $1.49 per mcfe. Reserve replacement through the drillbit was 583 bcfe, or 268% of production (including 43 bcfe from positive performance revisions and 25 bcfe from oil and natural gas price increases), or 50% of the total increase, at a cost of $1.46 per mcfe. Reserve replacement through acquisitions was 583 bcfe, or 267% of production, or 50% of the total increase, at a cost of $1.52 per mcfe. The above figures do not include the impact of the Hallwood and the three miscellaneous acquisitions, which closed or will close after the end of the 2005 second quarter.

Total costs incurred to acquire and develop proved reserves during the first half of 2005 were $2.26 per mcfe, which includes drilling, completion, acquisition, seismic, leasehold, capitalized internal costs, non-cash tax basis step-up from various corporate acquisitions ($252 million, or $0.22 per mcfe), asset retirement obligations and all other capitalized miscellaneous costs. 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.

As of June 30, 2005, the company's estimated future net cash flows discounted at 10% before taxes (PV-10) from its proved reserves were $14.6 billion using field differential adjusted prices of $52.35 per bo (based on a NYMEX quarter-end price of $56.72 per bo) and $6.41 per mcf (based on a NYMEX quarter-end price of $7.07 per mcf). Chesapeake's PV-10 changes by approximately $255 million for every $0.10 per mcf change in gas prices and approximately $48 million for every $1.00 per bo change in oil prices. The above figures do not include the impact of the Hallwood and the three miscellaneous acquisitions, which closed or will close after the end of the 2005 second quarter.

Company's Leasehold and 3-D Seismic Inventories Increase to 4.1 Million and 10.8 Million Net Acres; Non-Proven Reserves on the Company's Extensive Leasehold Now Exceed 5.0 Tcfe

Chesapeake's exploratory and development drilling programs and production enhancement operations continue to produce operational results that exceed the company's forecasts and distinguish the company among its peers. During the 2005 second quarter, Chesapeake drilled 224 gross (162 net) operated wells and participated in another 296 gross (34 net) wells operated by other companies. The company's drilling success rate was 97% for company-operated wells and 98% for non-operated wells. During the quarter, Chesapeake invested $400 million in operated wells (using an average of 73 operated rigs), $77 million in non- operated wells (using an average of approximately 65 non-operated rigs) and $105 million in acquiring new 3-D seismic data and new leasehold (excluding leasehold acquired through acquisitions).

During the past five years, Chesapeake has built what it believes to be the largest inventories of onshore leasehold (4.1 million acres) and 3-D seismic (10.8 million acres) in the U.S. On this leasehold, the company has identified more than an nine-year inventory of 14,000 drillsites on which it believes it can develop approximately 2.2 tcfe of proved undeveloped reserves and more than 5.0 tcfe of non-proven reserves.

Chesapeake characterizes its drilling activity by one of three play types: conventional, unconventional gas resource and emerging gas resource. The company's approximate leasehold and proved undeveloped and non-proven reserve totals are set forth below:

* 2.6 million net acres in its traditional conventional areas (i.e., much of the Mid-Continent, Permian, Gulf Coast, South Texas and other areas) on which it has identified more than 3,200 drillsites, 1.0 tcfe of proved undeveloped reserves and more than 1.4 tcfe of non-proven reserves;

* 0.9 million net acres in its unconventional gas resource areas (i.e., Sahara, Granite/Cherokee/Atoka Washes, Hartshorne CBM, Barnett Shale and Ark-La-Tex tight sands) on which it has identified more than 10,000 drillsites, 1.1 tcfe of proved undeveloped reserves and more than 2.8 tcfe of non-proven reserves; and,

* 0.6 million net acres in its emerging gas resource areas (i.e., Fayetteville Shale, Caney/Woodford Shales, Haley Deep and others) on which it has identified more than 900 drillsites, less than 0.1 tcfe of proved undeveloped reserves and more than 0.8 tcfe of non-proven reserves.

Chesapeake continues to actively acquire more acreage in all three play types with more than 500,000 acres acquired in the 2005 second quarter through an aggressive land acquisition program that continually utilizes more than 450 land brokers in the field researching land records and acquiring leases.

Chesapeake Continues to Increase Investments in Drilling Rigs and Estimates Fair Value of its Drilling Rig Investments Exceeds Cost Basis by $150 Million to Date

In 2003, Chesapeake began an aggressive program of hedging its exposure to expected increases in service industry costs by initiating a program of investing directly and indirectly in drilling rigs. To date, the company's investments consist of the following:

* a 100% interest in Chesapeake's wholly owned drilling subsidiary, Nomac Drilling Corporation. Nomac presently owns 14 rigs, all of which are drilling Chesapeake-operated wells, and has an additional 18 rigs on order for delivery later in 2005 and in 2006. The company's cost basis in its existing 14 rigs is $80 million and Chesapeake believes Nomac's fair market value now exceeds $150 million.

* a 17% interest in Pioneer Drilling Corporation . This interest was acquired in three separate transactions and has resulted in Chesapeake investing $43 million to date in PDC for an average cost basis of $5.55 per share. Based on PDC's closing stock price on August 3 of $16.09, the company's unrealized gain to date on this investment is $81 million. Pioneer owns 50 rigs and has an additional 7 rigs on order.

* a 45% interest in DHS Drilling Company, a Casper, Wyoming-based drilling rig company which has four rigs operating in the Rocky Mountains and which plans to expand to ten rigs over the next several months. Chesapeake has invested $15 million in DHS to date.

* a 49% interest in Mountain Drilling Company, a newly formed venture with a New York based investment banking firm in which Chesapeake and

its partner have each invested $25 million to secure four specialty rigs for drilling in urban areas or in areas of special environmental sensitivity.

In addition, the company is sponsoring the construction of approximately another 20 rigs through various intermediate-term drilling contracts with third party rig builders and operators. In total, Chesapeake believes its $163 million of rig investments have appreciated in value by more than $150 million and have or will increase the U.S. drilling rig fleet by approximately 50 rigs from 2004 to 2006.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "Today's announcement of very strong operational and financial results for the 2005 second quarter provides ongoing confirmation that Chesapeake's business strategy continues to create significant shareholder value. This strategy has generated a 75% increase in our common stock price during the past year and an approximate 20-fold increase since our IPO in February 1993 through:

* delivering consistent and value-added growth through a balance of acquisitions and exploratory and developmental 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.

"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 Friday morning, August 5, 2005 at 9:00 a.m. EDT to discuss this earnings release. The telephone number to access the conference call is 913.981.5592. For those unable to participate in the conference call, a replay will be available from 12:00 noon EDT, August 5, 2005 through midnight EDT on August 19, 2005. The number to access the conference call replay is 719.457.0820 and the passcode is 2749019. The conference call will also be simulcast live on the Internet and can be accessed at http://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 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.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in item 1 of our 2004 Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 9, 2005. They include the volatility of oil and gas prices; adverse effects our level of indebtedness could have on our operations and future growth; our ability to compete effectively against strong independent oil and gas companies and majors; the availability of capital on an economic basis to fund reserve replacement costs; uncertainties inherent in estimating quantities of oil and gas reserves and projecting future rates of production and the timing of development expenditures; our ability to replace reserves and sustain production; uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities; unsuccessful exploration and development drilling; declines in the values of our oil and gas properties resulting in ceiling test write-downs; lower prices realized on oil and gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; and drilling and operating risks. 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. Also, our internal estimates of reserves, particularly those in the properties recently acquired or proposed to be acquired where we may have limited review of data or experience with the reserves, may be subject to revision and may be different from estimates by our external reservoir engineers at year-end. 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", "possible" or "non-proven" 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 being actually realized by the company. While we believe our calculations of non-proven drillsites and estimation of non-proven reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

The announcement of proposed financings through the issuance of equity and/or senior notes in this press release shall not constitute an offer to sell or a solicitation of an offer to buy the securities. The terms of any such offerings have not been decided. The securities may not be registered under the Securities Act of 1933 or any state securities laws and, if not registered, may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act and state laws.

Chesapeake Energy Corporation is the third 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 property acquisitions in the Mid-Continent, Permian Basin, South Texas, Texas Gulf Coast and Ark-La-Tex (including the Barnett Shale) regions of the United States. The company's Internet address is http://www.chkenergy.com/ .

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

	Three Months Ended June 30, 2005		Three Months Ended June 30, 2004	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and gas sales	772,401	6.83	399,665	4.62
Oil and gas marketing sales	275,617	2.43	174,627	2.02
Total Revenues	1,048,018	9.26	574,292	6.64
OPERATING COSTS:				
Production expenses	72,333	0.64	49,595	0.57
Production taxes	47,253	0.42	22,751	0.26
General and administrative expenses:				
General and administrative (excluding stock-based compensation)	9,282	0.08	7,420	0.09
Stock-based compensation	2,506	0.02	672	0.01
Oil and gas marketing expenses	270,003	2.39	171,115	1.98
Oil and gas depreciation, depletion, and amortization	209,371	1.85	136,743	1.58
Depreciation and amortization of other assets	11,807	0.10	6,716	0.08
Total Operating Costs	622,555	5.50	395,012	4.57
INCOME FROM OPERATIONS	425,463	3.76	179,280	2.07
OTHER INCOME (EXPENSE):				
Interest and other income	2,005	0.02	1,335	0.01
Interest expense	(53,902)	(0.48)	(28,806)	(0.33)
Loss on repurchases or exchanges of Chesapeake debt	(68,400)	(0.60)	---	---
Total Other Income (Expense)	(120,297)	(1.06)	(27,471)	(0.32)
Income Before Income Taxes	305,166	2.70	151,809	1.75
Income Tax Expense:				
Current	---	---	---	---
Deferred	111,387	0.99	54,654	0.63
Total Income Tax Expense	111,387	0.99	54,654	0.63
NET INCOME	193,779	1.71	97,155	1.12
Preferred stock dividends	(9,859)	(0.09)	(11,344)	(0.13)
Loss on conversion/exchange of preferred stock	(4,743)	(0.04)	---	---
NET INCOME AVAILABLE TO				

COMMON SHAREHOLDERS	179,177	1.58	85,811	0.99

EARNINGS PER COMMON SHARE:		
Basic	$ 0.58	$ 0.36
Assuming dilution	$ 0.52	$ 0.30

WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's):		
Basic	311,181	241,147
Assuming dilution	364,063	322,194

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

	Six Months Ended June 30, 2005		Six Months Ended June 30, 2004	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and gas sales	1,311,343	6.01	819,458	4.95
Oil and gas marketing sales	520,125	2.39	317,963	1.92
Total Revenues	1,831,468	8.40	1,137,421	6.87
OPERATING COSTS:				
Production expenses	141,895	0.65	94,398	0.57
Production taxes	83,211	0.38	37,687	0.23
General and administrative expenses:				
General and administrative (excluding stock-based compensation)	18,932	0.09	15,586	0.09
Stock-based compensation	4,923	0.02	2,541	0.02
Oil and gas marketing expenses	507,279	2.33	310,779	1.87
Oil and gas depreciation, depletion, and amortization	390,339	1.79	256,651	1.55
Depreciation and amortization of other assets	21,889	0.10	12,455	0.08
Total Operating Costs	1,168,468	5.36	730,097	4.41
INCOME FROM OPERATIONS	663,000	3.04	407,324	2.46
OTHER INCOME (EXPENSE):				
Interest and other income	5,362	0.02	2,678	0.02
Interest expense	(97,030)	(0.44)	(75,351)	(0.46)
Loss on repurchases or exchanges of Chesapeake debt	(69,300)	(0.32)	(6,925)	(0.04)
Total Other Income (Expense)	(160,968)	(0.74)	(79,598)	(0.48)
Income Before Income Taxes	502,032	2.30	327,726	1.98

Income Tax Expense:				
Current	---	---	---	---
Deferred	183,243	0.84	117,981	0.71
Total Income Tax Expense	183,243	0.84	117,981	0.71
NET INCOME	318,789	1.46	209,745	1.27
Preferred stock dividends	(15,322)	(0.07)	(19,512)	(0.12)
Loss on conversion/exchange of preferred stock	(4,743)	(0.02)	---	---
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	298,724	1.37	190,233	1.15
EARNINGS PER COMMON SHARE:				
Basic	$0.96		$0.80	
Assuming dilution	$0.88		$0.67	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's):				
Basic	310,523		239,016	
Assuming dilution	356,478		310,937	

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

	June 30, 2005	December 31, 2004
Cash	$ ---	$ 6,896
Other current assets	572,006	560,644
Total Current Assets	572,006	567,540
Property and equipment (net)	9,803,357	7,444,384
Other assets	282,523	232,585
Total Assets	$10,657,886	$8,244,509
Current liabilities	$ 1,165,844	$ 963,953
Long term debt	4,125,929	3,075,109
Asset retirement obligation	82,938	73,718
Other long term liabilities	70,270	34,973
Deferred tax liability	1,361,259	933,873
Total Liabilities	6,806,240	5,081,626
STOCKHOLDERS' EQUITY	3,851,646	3,162,883
TOTAL LIABILITIES & STOCKHOLDERS' EQUITY	$10,657,886	$8,244,509

COMMON SHARES OUTSTANDING	318,543	311,869

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF SIX MONTHS ENDED JUNE 30, 2005 COSTS INCURRED
($ in 000's, except per unit amounts)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe
Exploration and development costs (A)	$ 853,424	583,227	$ 1.46
Acquisition of proved properties	885,052	583,092	1.52
Subtotal	1,738,476	1,166,319	1.49
Acquisition of unproved properties	502,374	---	---
Divestitures	(114)	(5)	---
Leasehold acquisition costs	90,976	---	---
Geological and geophysical costs	26,620	---	---
Adjusted subtotal	2,358,332	1,166,314	2.02
Tax basis step-up	251,659	---	---
Asset retirement obligation and other	21,996	---	---
Total	$2,631,987	1,166,314	$ 2.26

(A) Reserves include revisions to previous estimates

CHESAPEAKE ENERGY CORPORATION
ROLLFORWARD OF PROVED RESERVES
(unaudited)

	Mmcfe
Beginning balance, 12/31/04	4,901,751
Extensions and discoveries	515,199
Acquisitions	583,092
Divestitures	(5)
Revisions-performance	42,541
Revisions-price	25,487
Production	(217,807)
Ending balance, 6/30/05	5,850,258
Reserve replacement	1,166,314
Reserve replacement rate	535%

CHESAPEAKE ENERGY CORPORATION
SUPPLEMENTAL DATA - OIL & GAS SALES AND INTEREST EXPENSE
(in 000's)
(unaudited)

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Oil and Gas Sales ($ in thousands):				
Oil sales	$96,798	$59,930	$176,742	$107,961
Oil derivatives - realized gains (losses)	(10,650)	(12,878)	(17,717)	(21,208)
Oil derivatives - unrealized gains (losses)	10,900	(1,470)	(1,942)	(7,489)
Total Oil Sales	$97,048	$45,582	$157,083	$79,264
Gas sales	$635,901	$415,216	$1,171,678	$775,317
Gas derivatives - realized gains (losses)	(33,702)	(42,453)	13,713	(8,462)
Gas derivatives - unrealized gains (losses)	73,154	(18,680)	(31,131)	(26,661)
Total Gas Sales	$675,353	$354,083	$1,154,260	$740,194
Total Oil and Gas Sales	$772,401	$399,665	$1,311,343	$819,458
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$48.11	$35.82	$47.03	$34.40
Gas ($ per mcf)	$6.29	$5.43	$6.00	$5.29
Gas equivalent ($ per mcfe)	$6.47	$5.49	$6.19	$5.34
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$42.82	$28.12	$42.32	$27.65
Gas ($ per mcf)	$5.95	$4.87	$6.07	$5.23
Gas equivalent ($ per mcfe)	$6.08	$4.85	$6.17	$5.16
Interest Expense ($ in thousands):				
Interest	$54,710	$37,513	$102,003	$76,077
Derivatives - realized (gains) losses	(675)	353	(1,796)	(405)
Derivatives - unrealized (gains) losses	(133)	(9,060)	(3,177)	(321)
Total Interest Expense	$53,902	$28,806	$97,030	$75,351

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

THREE MONTHS ENDED: June 30, June 30,

	2005	2004
Cash provided by operating activities	$566,781	$328,787
Cash (used in) investing activities	(1,365,941)	(864,016)
Cash provided by financing activities	799,160	422,041

SIX MONTHS ENDED:	June 30, 2005	June 30, 2004
Cash provided by operating activities	$1,080,307	$670,557
Cash (used in) investing activities	(2,539,878)	(1,599,450)
Cash provided by financing activities	1,452,675	964,549

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

THREE MONTHS ENDED:	June 30, 2005	June 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$ 566,781	$ 328,787
Adjustments:		
Changes in assets and liabilities	(53,498)	(20,614)
OPERATING CASH FLOW*	$ 513,283	$ 308,173

* 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: June 30, June 30,

	2005	2004
Net income	$ 193,779	$ 97,155
Income tax expense	111,387	54,654
Interest expense	53,902	28,806
Depreciation and amortization of other assets	11,807	6,716
Oil and gas depreciation, depletion and amortization	209,371	136,743
EBITDA**	$ 580,246	$ 324,074

** 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:	June 30, 2005	June 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$ 566,781	$ 328,787
Changes in assets and liabilities	(53,498)	(20,614)
Interest expense	53,902	28,806
Unrealized gains (losses) on oil and gas derivatives	84,054	(20,150)
Other non-cash items	(70,993)	7,245
EBITDA	$ 580,246	$ 324,074

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

SIX MONTHS ENDED:	June 30, 2005	June 30, 2004

CASH PROVIDED BY OPERATING ACTIVITIES	$1,080,307	$670,557
Adjustments:		
Changes in assets and liabilities	(61,561)	(28,830)
OPERATING CASH FLOW*	$1,018,746	$641,727

* 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.

SIX MONTHS ENDED:	June 30, 2005	June 30, 2004
Net income	$318,789	$209,745
Income tax expense	183,243	117,981
Interest expense	97,030	75,351
Depreciation and amortization of other assets	21,889	12,455
Oil and gas depreciation, depletion and amortization	390,339	256,651
EBITDA**	$1,011,290	$672,183

** 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:

SIX MONTHS ENDED:	June 30, 2005	June 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$1,080,307	$670,557
Changes in assets and liabilities	(61,561)	(28,830)
Interest expense	97,030	75,351
Unrealized gains (losses) on oil and gas derivatives	(33,073)	(34,150)
Other non-cash items	(71,413)	(10,745)
EBITDA	$1,011,290	$672,183

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON & ADJUSTED EBITDA

($ in 000's, except per share amounts)
(unaudited)

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net income available to common shareholders	$ 179,177	$ 298,724
Adjustments:		
Loss on conversion/exchange of preferred stock	4,743	4,743
Net Income	$ 183,920	$ 303,467
Adjustments, net of tax:		
Unrealized (gains) losses on derivatives	(53,458)	18,985
Loss on repurchases or exchanges of debt	43,434	44,006
Adjusted net income available to common*	$ 173,896	$ 366,458
Adjusted earnings per share assuming dilution**	$ 0.50	$ 1.06
EBITDA	$ 580,246	$1,011,290
Adjustments, before tax:		

Unrealized (gains) losses on oil and gas derivatives	(84,054)	33,073
Loss on repurchases or exchanges of debt	68,400	69,300
Adjusted EBITDA*	$ 564,592	$1,113,663

* Adjusted net income available to common and adjusted earnings per share assuming dilution and adjusted EBITDA 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 net income available to common and adjusted EBITDA to evaluate the company's operational trends and performance relative to other oil and gas producing companies.
b. Adjusted net income available to common 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 three and six months ended June 30, 2005, accounting rules prohibit the company from assuming the conversion of the 4.125% 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 366.7 million and 359.1 million for the three and six months ended June 30, 2005, respectively).

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF AUGUST 4, 2005

Quarter Ending September 30, 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 August 4, 2005, we are using the following key assumptions in our projections for the second quarter of 2005, the full-year 2005 and the full-year 2006.

The primary changes from our May 2, 2005 Outlook are in italicized bold in the table and are explained as follows:

1) We have updated the projected effects from changes in our hedging positions since our May 2, 2005 Outlook.
2) We have updated certain of our cost and oil and natural gas price differentials to reflect changing market conditions.

3) We have included our expectations for future NYMEX oil and gas prices to illustrate hedging effects only.
4) We have increased our capital expenditure projections to reflect anticipated higher levels of drilling activity and continuing service cost inflation.

	Quarter Ending September 30, 2005	Year Ending December 31, 2005	Year Ending December 31, 2006
Estimated Production:			
Oil - Mbo	1,950	7,650	7,700
Gas - Bcf	107-109	411-417	465-475
Gas Equivalent - Bcfe	118.5-120.5	457-463	511-521
Daily gas equivalent midpoint - in Mmcfe	1,300	1,260	1,414
NYMEX Prices (for calculation of realized hedging effects only):			
Oil - $/Bo	$53.01	$51.51	$45.00
Gas - $/Mcf	$7.04	$6.64	$6.50
Estimated Differentials to NYMEX Prices:			
Oil - $/Bo	-$4.50	-$4.46	-$4.50
Gas - $/Mcf	-$0.80	-$0.75	-$0.80
Estimated Realized Hedging Effects (based on expected NYMEX prices above):			
Oil - $/Bo	-$0.33	-$2.07	$4.34
Gas - $/Mcf	-$0.20	$0.19	$0.33
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.68-0.72	$0.68-0.72	$0.72-0.77
Production taxes (generally 7% of O&G revenues)(A)	$0.43-0.48	$0.40-0.45	$0.40-0.45
General and administrative	$0.10-0.12	$0.10-0.12	$0.11-0.13
Stock-based compensation (non-cash)	$0.03-0.05	$0.03-0.05	$0.04-0.06
DD&A - oil and gas	$1.85-1.95	$1.80-1.90	$2.00-2.10
Depreciation of other assets	$0.09-0.11	$0.09-0.11	$0.10-0.12
Interest expense(B)	$0.45-0.49	$0.45-0.49	$0.48-0.52
Other Income and Expense per Mcfe:			
Marketing and other income	$0.02-0.04	$0.02-0.04	$0.02-0.04
Book Tax Rate (approximately equal to 95% deferred)	36.5%	36.5%	36.5%
Equivalent Shares Outstanding:			
Basic	318 mm	315 mm	320 mm
Diluted	372 mm	366 mm	375 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$485-$535mm	$1,900-$2,100mm	$2,100-$2,300mm

(A) Severance tax per mcfe is based on NYMEX prices of $50.00 per bo and natural gas prices ranging from $5.75 to $8.00 per mcf during Q3 2005, $45.00 per bo and natural gas prices ranging from $6.00 to $8.50 per mcf during calendar 2005 and $45.00 per bo and $6.35 to $7.25 per mcf during calendar 2006.

(B) 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 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 loses 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	Assuming Gas Production in Bcf's of:	% Hedged Open Swap Positions as a % of Estimated Total Gas Production
2005:						
3rd Qtr	72.3	$6.61	-$0.15	$6.46	108.0	67%
4th Qtr	57.4	$7.08	-$0.19	$6.89	110.8	52%
Remaining 2005 (A)	129.7	$6.82	-$0.17	$6.65	218.8	59%
Total 2006 (A)	128.6	$7.42	-$0.19	$7.23	470.0	27%
Total 2007	9.9	$8.24	-$1.18	$7.06	505.0	2%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 42.6 bcf in 2005 and $3.75 to $5.50 covering 35.7 bcf in 2006.

Note: Not shown above are collars covering 3.0 bcf of production in 2005 at a weighted average floor and ceiling of $3.59 and $5.37 and 0.2 bcf of production in 2006 at a weighted average floor and ceiling of $6.00 and $9.70 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
Remaining 2005	96.3	$ 0.27	218.8	44%
2006	130.1	0.32	470.0	28%
2007	126.5	0.28	505.0	25%
2008	118.6	0.27	530.0	22%
2009	86.6	0.29	555.0	16%
Totals	558.1	$ 0.29	2,278.8	24%

* weighted average

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

% Hedged
Open Swap
Positions as %

	Open Swaps in mbo's	Avg. NYMEX Strike Price	Assuming Oil Production in mbo's of:	of Total Estimated Production
Q3 - 2005	888.5	$51.41	1,950	46%
Q4 - 2005	935.5	$52.99	1,942	48%
Remaining 2005(A)	1,824.0	$52.22	3,892	47%
Total 2006(A)	2,842.5	$56.75	7,700	37%
Total 2007	590.0	$53.33	7,750	8%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $26.00 to $42.00 covering 552 mbo in 2005 and $40.00 to $42.00 covering 501.5 mbo in 2006.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF MAY 2, 2005
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF AUGUST 4, 2005

Quarter Ending June 30, 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 May 2, 2005, we are using the following key assumptions in our projections for the second quarter of 2005, the full-year 2005 and the full-year 2006.

The primary changes from our April 12, 2005 Outlook are in italicized bold in the table and are explained as follows:

1) We have updated the projected effects from changes in our hedging positions since our April 12, 2005 Outlook.
2) We have updated certain of our cost and oil and natural gas price differentials to reflect changing market conditions.
3) We have included our expectations for future NYMEX oil and gas prices to illustrate hedging effects only.
4) We have increased our capital expenditure projections to reflect anticipated higher levels of drilling activity and continuing service cost inflation.
5) We have increased our estimated diluted share count to reflect the common shares issuable upon conversion of our recently issued $460 million preferred stock issuance.

	Quarter Ending June 30, 2005	Year Ending December 31, 2005	Year Ending December 31, 2006
Estimated Production:			
Oil - Mbo	1,770	7,000	7,300
Gas - Bcf	98-100	403-411	457-467
Gas Equivalent - Bcfe	108.5-110.5	445-453	501-511

Daily gas equivalent midpoint -in Mmcfe	1,203	1,230	1,386
NYMEX Prices (for calculation of realized hedging effects only):			
Oil - $/Bo	$45.00	$46.21	$45.00
Gas - $/Mcf	$6.78	$6.51	$6.50
Estimated Differentials to NYMEX Prices:			
Oil - $/Bo	-$4.00	-$4.00	-$4.00
Gas - $/Mcf	-$0.80	-$0.80	-$0.80
Estimated Realized Hedging Effects (based on expected NYMEX prices above):			
Oil - $/Bo	-$0.65	-$0.65	$1.52
Gas - $/Mcf	-$0.25	$0.17	$0.11
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.68-0.72	$0.68-0.72	$0.72-0.77
Production taxes (generally 7% of O&G revenues) (A)	$0.40-0.45	$0.40-0.45	$0.40-0.45
General and administrative	$0.10-0.12	$0.10-0.12	$0.11-0.13
Stock-based compensation (non-cash)	$0.03-0.05	$0.03-0.05	$0.04-0.06
DD&A - oil and gas	$1.75-1.85	$1.75-1.85	$1.85-1.95
Depreciation of other assets	$0.09-0.11	$0.09-0.11	$0.10-0.12
Interest expense (B)	$0.43-0.47	$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
Book Tax Rate (approximately equal to 95% deferred)	36.5%	36.5%	36.5%
Equivalent Shares Outstanding:			
Basic	312 mm	315 mm	318 mm
Diluted	370 mm	366 mm	373 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$425-$475mm	$1,700-$1,900mm	$1,900-$2,100mm

(A) Severance tax per mcfe is based on NYMEX prices of $45.00 per barrel of oil and natural gas prices ranging from $6.00-$7.20 during Q2 2005, $6.50-$7.50 during calendar 2005, and $6.35-$7.25 during calendar 2006.

(B) 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 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 loses 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:

			% Hedged	
		Avg.		
Avg.		NYMEX		Open Swap
NYMEX	Gain	Price	Assuming	Positions
Strike	(Loss)	Including	Gas	as a %

	Open Swaps in Bcf's	Price Of Open Swaps	from Locked Swaps	Open & Locked Positions	Production in Bcf's of:	of Estimated Total Gas Production
2005:						
1st Qtr	62.2	$7.00	-$0.18	$6.82	94.1	66%
2nd Qtr	64.0	$6.30	-$0.16	$6.14	99.0	65%
3rd Qtr	59.8	$6.46	-$0.18	$6.28	105.5	57%
4th Qtr	40.9	$6.73	-$0.27	$6.46	108.4	38%
Total 2005(A)	226.9	$6.61	-$0.19	$6.42	407.0	56%
Total 2006(A)	82.1	$7.14	-$0.29	$6.85	462.0	18%
TOTALS 2005-2006	309.0	$6.75	-$0.22	$6.53	869.0	36%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 79.5 bcf in 2005 and $3.75 to $5.50 covering 35.7 bcf in 2006.

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	407.0	46%
2006	130.1	0.32	462.0	28%
2007	126.5	0.28	490.0	26%
2008	118.6	0.27	515.0	23%
2009	86.6	0.29	540.0	16%
Totals	650.4	$ 0.28	2,414.0	27%

* 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	1,746	50%

Q2 - 2005	1,137.0	$43.98	1,750	65%
Q3 - 2005	614.0	$48.46	1,750	35%
Q4 - 2005	521.5	$48.46	1,754	30%
Total 2005 (A)	3,143.0	$45.01	7,000	45%
Total 2006 (A)	1,200.0	$54.77	7,300	16%
Total 2007	365.0	$50.79	7,300	5%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $26.00 to $42.00 covering 2,317 mbo in 2005 and $40.00 to $42.00 covering 501.5 mbo in 2006.

SOURCE: Chesapeake Energy Corporation

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