NEWS RELEASE

Chesapeake Energy Corporation Reports Record Results for the 2006 First Quarter

Net Income Available to Common Shareholders Reaches $604 Million on Revenue of $1.94 Billion and Production of 137 Bcfe
Company Expects Total Production Growth of 24% in 2006 and 7-10% in 2007; Proved Reserves Reach Record Level of 7.8 Tcfe
Company Increases Hedges at Very Attractive Prices; Has Now Hedged 80%, 56% and 41% of Expected Full-Year 2006, 2007 and 2008 Oil and Natural Gas Production at Average NYMEX Prices of $9.45, $9.98 and $9.36 Per Mcfe

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OKLAHOMA CITY

Chesapeake Energy Corporation today reported financial and operating results for the first quarter of 2006. For the quarter, Chesapeake generated net income available to common shareholders of $604 million ($1.44 per fully diluted common share), operating cash flow of $1.047 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.407 billion (defined as income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.945 billion and production of 137 billion cubic feet of natural gas equivalent (bcfe).

The company's 2006 first quarter 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 2006 first quarter reported results are described as follows:

* an unrealized mark-to-market gain of $122 million resulting from the company's oil and natural gas and interest rate hedging programs;

* a realized gain of $73 million resulting from the sale of the company's investment in the common stock of Pioneer Drilling Corporation ;

* a charge of $34 million relating to the acceleration of vesting of stock options and restricted stock in connection with the retirement in February 2006 of Chesapeake's President and Chief Operating Officer, Tom L. Ward; and

* a reduction of net income available to common shareholders of $1 million resulting from issuances of common stock upon various exchanges and conversions of preferred stock.

Excluding the above-mentioned items and giving effect to common shares issued for preferred shares during the period, Chesapeake's net income to common shareholders in the first quarter of 2006 would have been $444 million ($1.07 per fully diluted common share) and ebitda would have been $1.147 billion. 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 to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 15-16 of this release.

Oil and Natural Gas Production Sets Record for 19th Consecutive Quarter; 2006 First Quarter Average Daily Production Increases 31% and 7% Over Production in the 2005 First Quarter and 2005 Fourth Quarter, Respectively

Daily production for the 2006 first quarter averaged 1.519 bcfe, an increase of 357 million cubic feet of natural gas equivalent (mmcfe), or 31%, over the 1.162 bcfe of daily production in the 2005 first quarter and an increase of 101 mmcfe, or 7%, over the 1.418 bcfe produced per day in the 2005 fourth quarter. Of the 357 mmcfe increase in daily production from the year ago quarter, 42% was generated from organic drillbit growth and 58% was generated from acquisitions, with the company's trailing 12-month organic production growth rate calculated as 13%. Of the 101 mmcfe daily increase in sequential quarterly production, 22% was generated from organic drillbit growth and 78% was generated from acquisitions, with the company's sequential quarterly organic production growth rate calculated as 1.7%. Chesapeake is anticipating total production growth of 24% in 2006 and organic growth rates of at least 10% in 2006 and 7-10% in 2007.

Chesapeake's 2006 first quarter production of 136.8 bcfe was comprised of 124.1 billion cubic feet of natural gas (bcf) (91% on a natural gas equivalent basis) and 2.12 million barrels of oil and natural gas liquids (mmbbls) (9% on a natural gas equivalent basis). Chesapeake's average daily production for the quarter of 1.519 bcfe consisted of 1.378 bcf of natural gas and 23,511 barrels (bbls) of oil. The 2006 first quarter was Chesapeake's 19th consecutive quarter of sequential U.S. production growth. Over these 19 quarters, Chesapeake's U.S. production increased 280%, for an average compound quarterly growth rate of 7.3% and an average compound annual growth rate of 32.2%.

Average Prices Realized, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2006 first quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $57.12 per bbl and $9.61 per thousand cubic feet (mcf), for a realized natural gas equivalent price of $9.60 per thousand cubic feet of natural gas equivalent (mcfe). Chesapeake's average realized pricing differentials to NYMEX during the first quarter were a negative $5.04 per bbl and a negative $1.61 per mcf. Realized gains and losses from oil and natural gas hedging activities during the quarter generated a $1.80 loss per bbl and a $2.03 gain per mcf, for a 2006 first quarter realized hedging gain of $248 million, or $1.82 per mcfe.

During the past few weeks, Chesapeake has significantly added to its 2006, 2007 and 2008 oil and natural gas hedging positions previously announced on February 23, 2006. The following tables compare Chesapeake's hedged production volumes (including only swaps and excluding CNR's swaps) as of May 1, 2006 to those as of February 23, 2006.

Swap Positions as of May 1, 2006

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX

2006 1Q	76%	$10.72	52%	$60.03
2006 2Q	78%	$8.77	69%	$61.85
2006 3Q	86%	$8.75	84%	$63.90
2006 4Q	81%	$9.42	85%	$63.76
2006 Total	80%	$9.37	72%	$62.63
2007 Total	57%	$9.90	44%	$67.07
2008 Total	41%	$9.22	37%	$68.20

Swap Positions as of February 23, 2006

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2006 1Q	74%	$10.72	58%	$60.03
2006 2Q	73%	$8.82	67%	$61.13
2006 3Q	74%	$8.87	64%	$61.50
2006 4Q	64%	$9.36	62%	$61.33
2006 Total	71%	$9.43	63%	$61.02
2007 Total	36%	$9.85	22%	$62.42
2008 Total	22%	$9.10	14%	$65.48

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 2006 and 2007 forecasts are attached to this release in an Outlook dated May 1, 2006 labeled as Schedule "A", which begins on page 17. This Outlook has been changed from the Outlook dated February 23, 2006 (attached as Schedule "B", which begins on page 21) to reflect various updated information.

Key Operational and Financial Statistics Summarized Below
for the 2006 First Quarter

The table below summarizes Chesapeake's key results during the 2006 first quarter and compares them to the 2005 fourth quarter and first quarter:

	Three Months Ended:		
	3/31/06	12/31/05	3/31/05
Average daily production (in mmcfe)	1,519	1,418	1,162
Natural gas as % of total production	91	91	90
Natural gas production (in bcf)	124.1	118.3	94.1
Average realized natural gas price ($/mcf) (A)	9.61	8.08	6.20
Oil production (in mbbls)	2,116	2,014	1,746
Average realized oil price ($/bbl) (A)	57.12	52.65	41.74
Natural gas equivalent production (in bcfe)	136.8	130.4	104.6
Natural gas equivalent realized price ($/mcfe) (A)	9.60	8.14	6.27
Marketing income ($/mcfe)	.10	.10	.07
Service operations income ($/mcfe)	.11	---	---
Production expenses ($/mcfe)	(.87)	(.72)	(.66)

Production taxes ($/mcfe)	(.40)	(.55)	(.34)
General and administrative costs ($/mcfe) (B)	(.17)	(.15)	(.09)
Stock-based compensation ($/mcfe)	(.05)	(.04)	(.02)
DD&A of oil and natural gas properties ($/mcfe)	(2.23)	(2.09)	(1.73)
D&A of other assets ($/mcfe)	(.17)	(.12)	(.10)
Interest expense ($/mcfe) (A)	(.52)	(.49)	(.44)
Operating cash flow ($ in millions) (C)	1,046.9	832.8	504.6
Operating cash flow ($/mcfe)	7.66	6.39	4.82
Adjusted ebitda ($ in millions) (D)	1,147.2	887.7	549.1
Adjusted ebitda ($/mcfe)	8.39	6.81	5.25
Net income to common shareholders ($ in millions)	603.9	431.8	119.5

(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, as adjusted to remove the effects of certain items detailed on page 16.

Oil and Natural Gas Proved Reserves Reach Record Level of 7.8 Tcfe; Drilling and Acquisition Costs Average $2.13 per Mcfe as Company Adds 290 Bcfe for a Reserve Replacement Rate of 312%

Chesapeake began 2006 with estimated proved reserves of 7.521 trillion cubic feet of natural gas equivalent (tcfe) and ended the quarter with 7.811 tcfe, an increase of 290 bcfe, or 4%. During the 2006 first quarter, Chesapeake replaced its 137 bcfe of production with an estimated 427 bcfe of new proved reserves, for a reserve replacement rate of 312%. Reserve replacement through the drillbit was 184 bcfe, or 135% of production (including 76 bcfe of positive performance revisions and 88 bcfe of downward revisions resulting from oil and natural gas price declines between December 31, 2005 and March 31, 2006) and 43% of the total increase. Excluding the impact of downward revisions from lower oil and natural gas prices, Chesapeake's exploration and development costs through the drillbit were $2.26 per mcfe during the 2006 first quarter. Reserve replacement through acquisitions of proved reserves was 243 bcfe, or 177% of production and 57% of the total increase, at a cost of $1.86 per mcfe.

Total costs incurred during the 2006 first quarter, including drilling, completion, acquisition, seismic, leasehold, capitalized internal costs, non- cash tax basis step-up from corporate acquisitions, asset retirement obligations and all other miscellaneous costs capitalized to oil and natural gas properties, were $1.901 billion. Excluding costs of $718 million for leasehold and unproved properties acquired during the quarter and $87 million of tax basis step-up, asset retirement obligations and other costs, as well as downward revisions of proved reserves from lower oil and natural gas prices, the company's total finding and acquisition costs were $2.13 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves is presented on page 13 of this release.

As of March 31, 2006, Chesapeake's estimated future net cash flows discounted at 10% before income taxes (PV-10) were $17.6 billion using field differential adjusted prices of $62.06 per bbl (based on a NYMEX quarter-end price of $66.33 per bbl) and $6.69 per mcf (based on a NYMEX quarter-end price of $7.18 per mcf). In addition to the PV-10 value of its proved reserves, the book value of the company's other assets (including drilling rigs, land and buildings, investments in securities and other non-current assets) was $1.6 billion as of March 31, 2006.

By comparison, as of March 31, 2005, Chesapeake's PV-10 was $14.2 billion using field differential adjusted prices of $51.38 per bbl (based on a NYMEX quarter-end price of $55.32 per bbl) and $6.65 per mcf (based on a NYMEX quarter-end price of $7.17 per mcf). In addition to the PV-10 value of its proved reserves, the book value of the company's other assets (including drilling rigs, land and buildings, investments in securities and other non- current assets) was $0.6 billion as of March 31, 2005.

Chesapeake's PV-10 changes by approximately $300 million for every $0.10 per mcf change in natural gas prices and approximately $50 million for every $1.00 per bbl change in oil prices. The company calculates the standardized measure of future net cash flows in accordance with SFAS 69 only at year-end because applicable income tax information on properties, including recently acquired oil and natural gas interests, is not readily available at other times during the year. As a result, the company is not able to reconcile the March 31, 2006 and March 31, 2005 PV-10 values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects.

Company's Leasehold and 3-D Seismic Inventories Now Exceed 8.9 Million Net Acres and 12.3 Million Acres, Respectively; Estimated Unproved Reserves in Company's Inventory Now 9.2 Tcfe

Chesapeake's exploratory and development drilling programs and production enhancement operations on its existing and acquired properties continue to produce operational results that distinguish the company among its peers. During the 2006 first quarter, Chesapeake drilled 262 gross (210 net) operated wells and participated in another 371 gross (45 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 $505 million in operated wells (using an average of 77 operated rigs), $110 million in non-operated wells (using an average of 75 non-operated rigs) and $200 million in acquiring new 3-D seismic data and leases (exclusive of leases acquired through acquisitions).

Chesapeake attributes its strong organic growth rates during the 2006 first quarter and in this decade to management's early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry -- people, land and seismic. Since 2000, Chesapeake has invested $3.8 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be the largest inventories of onshore leasehold (8.9 million net acres) and 3-D seismic (12.3 million acres) in the U.S. On this leasehold, the company has more than a 10-year drilling inventory of an estimated 29,000 drilling locations on which it believes it can develop approximately 2.8 tcfe of proved undeveloped reserves and approximately 9.2 tcfe of unproved reserves.

In addition, Chesapeake has significantly strengthened its technical capabilities during the past five years by increasing its land, geoscience and engineering staff by 425% to over 650 employees. Today, the company has more than 3,600 employees, of which approximately 70% work in the company's E&P operations and 30% work in the company's oilfield service operations.

Chesapeake characterizes its drilling activity by one of four play types: conventional gas resource, unconventional gas resource, emerging gas resource and Appalachian Basin gas resource. In these plays, Chesapeake uses a probability-weighted statistical approach to estimate the potential number of drillsites and potential unproved reserves associated with such drillsites. The company's leasehold, proved undeveloped and estimated potential unproved reserve totals by play type are set forth below:

* 2.9 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 approximately 2,700 drillsites, 1.0 tcfe of proved undeveloped reserves and approximately 1.0 tcfe of unproved reserves;

* 1.1 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 approximately 14,000 drillsites, 1.3 tcfe of proved undeveloped reserves and approximately 4.5 tcfe of unproved reserves;

* 1.5 million net acres in its emerging gas resource areas (i.e., Fayetteville Shale, Caney/Woodford Shales, Deep Haley, Deep Bossier and others) on which it has approximately 2,400 drillsites, 0.1 tcfe of proved undeveloped reserves and approximately 2.0 tcfe of unproved reserves; and

* 3.4 million net acres in the Appalachian Basin, where play types range from conventional to unconventional to emerging gas resource. On its significant Appalachian Basin acreage base acquired from CNR in November 2005, Chesapeake has approximately 10,000 drillsites, 0.4 tcfe of proved undeveloped reserves and more than 1.7 tcfe of unproved reserves.

Chesapeake continues to actively acquire more acreage throughout its operating areas, having acquired approximately 500,000 net acres in the 2006 first quarter through an aggressive land acquisition program that is currently utilizing almost 1,000 contract landmen in the field.

Chesapeake's most significant land acquisition activities during the quarter took place in the Arkansas Fayetteville Shale, Deep Bossier and other East Texas plays in which the company now owns more than 1,000,000, 150,000 and 125,000 net acres, respectively. To date, Chesapeake has drilled five vertical and two horizontal wells in the Fayetteville Shale and now has three operated rigs in the play drilling horizontal wells. If results are encouraging, the company may increase its drilling activity in the Fayetteville Shale later this year. In addition, Chesapeake will drill its first Deep Bossier well in East Texas and its first horizontal Woodford well in Southeastern Oklahoma this summer.

The company continues to achieve outstanding drilling results in the Barnett Shale play of Johnson and Tarrant Counties, Texas. To date, Chesapeake has drilled and completed 83 Barnett Shale horizontal wells and has current daily net production of 110 mmcfe (145 mmcfe gross). According to our recent review of the State of Texas' production records as accessed through the database of the Energy Division of IHS Inc., Chesapeake's Barnett Shale wells have been the most productive in the industry as calculated by peak month average daily production per horizontal well as set forth in the table below.

Company	Reported Number of Barnett Shale Horizontal Wells	Peak Month Average Production Per Horizontal Well (mcfe)	Peak Month Average Daily Production Per Horizontal Well (mcfe)
Chesapeake	40	76,783	2,524
XTO	108	60,718	1,996
Chief (private)	65	58,280	1,916
EOG	60	52,544	1,727
Devon	212	51,090	1,680
EnCana	84	41,658	1,370
Quicksilver	27	29,847	981
ConocoPhillips (Burlington)	46	27,230	895

Source: The Energy Division of IHS, Inc. based on production reported through January 2006 and including only operators of more than 25 horizontal wells.

The company believes this achievement reflects its substantial experience in drilling and completing horizontal wells in the U.S. Chesapeake has drilled more horizontal wells than any other company in the industry and believes it is the only company currently active in all of the following shale plays: the Barnett and Woodford Shale in West Texas; the Barnett Shale near Fort Worth, Texas; the Caney and Woodford Shales in southeastern Oklahoma; the Fayetteville Shale in Arkansas; the New Albany Shale in Illinois and Kentucky; and various Devonian Shale plays in Appalachia. Because of this unique position in the industry, the company believes that it has the distinct opportunity and competitive advantage to transfer knowledge and technology across all of the major shale plays east of the Rockies. Also, when combined with Chesapeake's expertise and activity level in various tight gas sand plays in the southwestern U.S. and Appalachia, Chesapeake believes it has established the leading natural gas resource base in the U.S.

Chesapeake Records Gain from Sale of Pioneer Drilling Corporation Common Stock

and Incurs Charge Related to Early Retirement of Tom L. Ward

In February, Chesapeake elected to sell its 17% ownership interest in the common stock of Pioneer Drilling Corporation as public company valuations for onshore U.S. land drilling rigs reached levels that substantially exceeded the private market valuation of comparable rigs. On February 10, 2006, Chesapeake sold its 7.7 million shares of Pioneer and received proceeds of $159 million. The sale resulted in a pre-tax gain to Chesapeake of $117 million, or a pre- tax profit margin of 275%, on an investment which had an average holding period of approximately 2.3 years. With proceeds from the Pioneer sale, the company acquired 13 U.S. onshore drilling rigs from privately-owned Martex Drilling Company for $150 million in February 2006.

The Martex acquisition bolstered the company's 100% owned drilling rig subsidiary, Nomac Drilling Corporation, in which to date Chesapeake has invested a total of $283 million to build or acquire 34 operating rigs, has invested another $47 million in 23 rigs that Nomac is currently building and has budgeted an additional $157 million for completion of these rigs. In total, Chesapeake's rig fleet should reach 57 rigs within the next 12 months, which should represent one of the ten largest drilling rig fleets in the

U.S.

Chesapeake has also invested $52 million in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns 45% and 49%, respectively. DHS owns 12 rigs and has three more rigs under construction. Mountain owns one rig and has ordered another nine rigs for delivery later in 2006 and 2007. Chesapeake's rig investments have served as an effective hedge to rising service costs and have also provided competitive advantages in making acquisitions and in developing its own leasehold on a more timely and efficient basis.

Also in the quarter, Chesapeake's co-founder, President and Chief Operating officer, Tom L. Ward, announced his retirement from the company and his resignation from the Board of Directors. As part of a negotiated separation agreement, Mr. Ward agreed to remain as a consultant to the company for no cash compensation through the term of his non-compete agreement, which expires on August 10, 2006. In recognition of Mr. Ward's role as a co-founder of the company and a key member of the senior management team that has guided Chesapeake to the second best stock price performance in the E&P industry since the company's IPO in February 1993 (and the #1 stock price performance since January 1, 1999 among all U.S. public companies with starting market capitalizations of greater than $50 million), the company's Board agreed to accelerate the vesting of Mr. Ward's unvested stock options and restricted stock. In connection with the early vesting, Chesapeake recognized an after- tax charge of $34 million during the 2006 first quarter. Subsequently, Mr. Ward exercised all of his stock options on March 14, 2006 and paid the company an aggregate exercise price of $37 million.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to again report outstanding financial and operational results for the 2006 first quarter. The company delivered top-tier production growth from both the drillbit and acquisitions as well as record margins as higher oil and natural gas price realizations far outpaced modest cost inflation. We have also opportunistically hedged service costs and a substantial portion of our anticipated production over the next three years at exceptional prices in order to ensure strong profitability when others in the industry are likely to face margin compression.

"In light of continued strong returns available through the drillbit on our extensive prospect inventory, we continue to increase our industry leading U.S. drilling activity. We currently have 87 operated rigs working to generate new supplies of clean-burning, domestically-produced natural gas, up from an average of 73 operated rigs last year, and we anticipate increasing our drilling activity to over 100 operated rigs by year-end. This increase in drilling activity creates the potential for increased production levels in 2006 and 2007 and will allow an accelerated drilling program in several key areas including: the Barnett Shale, where we plan to operate an average of at least 12 rigs this year versus an average of four rigs last year; Sahara, where we plan to operate an average of 12 rigs this year versus an average of nine rigs last year; and, following the successful integration of CNR, we now plan to accelerate drilling in Appalachia to 10-12 rigs, up from four rigs at the time of acquisition last November.

"We are also pleased to be recognized by Fortune this year as one the country's 500 largest corporations. In that survey, we were ranked #451 by revenues, #226 by market value, #206 by assets, #178 by total profits, #28 by profits as a percentage of revenues, and, most importantly, #11 by total return to shareholders (an exceptional 94% in 2005). In addition, during the quarter we were also added to the S&P 500 Index.

"The inclusion of Chesapeake in the Fortune 500 and S&P 500 Index is a reminder of how well the company's business strategy has worked for investors, royalty owners, consumers and other company stakeholders over the years. Since our IPO on February 4, 1993, we have delivered an approximate 2,300% increase in our common stock price. Our business strategy features delivering growth through a balance of acquisitions and organic drilling, focusing on clean-burning, domestically-produced natural gas to take advantage of strong long-term natural gas supply and demand fundamentals, building dominant regional scale to achieve low operating costs and high returns on capital and successfully mitigating financial and operational risks. We believe Chesapeake's management team can continue the successful execution of the company's distinctive business strategy and continue to deliver significant value to the company's investors for years to come."

Conference Call Information

A conference call has been scheduled for Tuesday morning, May 2, 2006 at 9:00 a.m. EDT to discuss this release. The telephone number to access the conference call is 913.981.4911 and the confirmation code is 1324430. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 am EDT. For those unable to participate in the conference call, a replay will be available from 12:00 p.m. EDT, May 2, 2006 through midnight EDT on May 15, 2006. The number to access the conference call replay is 719.457.0820 and the passcode for the replay is 1324430. The conference call will also be webcast 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 our website indefinitely.

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 natural gas reserves, expected oil and natural gas production and future expenses, projections of future oil and natural 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 1A of our 2005 Form 10-K filed with the Securities and Exchange Commission on March 14, 2006. They include the volatility of oil and natural gas prices; the limitations our level of indebtedness may have on our financial flexibility; our ability to compete effectively against strong independent oil and natural gas companies and majors; the availability of capital on an economic basis to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures; uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities; our ability to effectively consolidate and integrate acquired properties and operations; unsuccessful exploration and development drilling; declines in the values of our oil and natural gas properties resulting in ceiling test write-downs; lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; the negative impact lower oil and natural gas prices could have on our ability to borrow; 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 natural 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 "unproved" to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

Chesapeake Energy Corporation is the second 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 corporate and property acquisitions in the Mid-Continent, Permian Basin, South Texas, Texas Gulf Coast, Barnett Shale, Ark-La-Tex and Appalachian Basin 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:	March 31, 2006		March 31, 2005	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	1,510,821	11.05	538,942	5.15
Marketing sales	404,367	2.96	244,508	2.34
Service operations revenue	29,379	0.21	---	---
Total Revenues	1,944,567	14.22	783,450	7.49
OPERATING COSTS:				
Production expenses	119,392	0.87	69,562	0.66
Production taxes	55,373	0.40	35,958	0.34
General and administrative expenses	28,791	0.21	12,067	0.12
Marketing expenses	391,360	2.87	237,276	2.27

Service operations expense	14,437	0.11	---	---
Oil and natural gas depreciation, depletion and amortization	304,957	2.23	180,968	1.73
Depreciation and amortization of other assets	23,872	0.17	10,082	0.10
Early retirement expense	54,753	0.40	---	---
Total Operating Costs	992,935	7.26	545,913	5.22
INCOME FROM OPERATIONS	951,632	6.96	237,537	2.27
OTHER INCOME (EXPENSE):				
Interest and other income	9,636	0.07	3,357	0.03
Interest expense	(72,658)	(0.53)	(43,128)	(0.41)
Gain on sale of investment	117,396	0.86	---	---
Loss on repurchases or exchanges of Chesapeake debt	---	---	(900)	(0.01)
Total Other Income (Expense)	54,374	0.40	(40,671)	(0.39)
Income Before Income Taxes	1,006,006	7.36	196,866	1.88
Income Tax Expense:				
Current	---	---	---	---
Deferred	382,283	2.80	71,856	0.69
Total Income Tax Expense	382,283	2.80	71,856	0.69
NET INCOME	623,723	4.56	125,010	1.19
Preferred stock dividends	(18,812)	(0.13)	(5,463)	(0.05)
Loss on exchange/conversion of preferred stock	(1,009)	(0.01)	---	---
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	603,902	4.42	119,547	1.14
EARNINGS PER COMMON SHARE:				
Basic	$1.64		$0.39	
Assuming dilution	$1.44		$0.36	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)				
Basic	368,625		309,857	
Assuming dilution	431,455		351,357	

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

	March 31, 2006	December 31, 2005

Cash	$38,286	$60,027
Other current assets	1,155,910	1,123,370
Total Current Assets	1,194,196	1,183,397
Property and equipment (net)	16,307,278	14,411,887
Other assets	550,886	523,178
Total Assets	$18,052,360	$16,118,462
Current liabilities	$1,591,931	$1,964,088
Long term debt	6,320,915	5,489,742
Asset retirement obligation	166,249	156,593
Other long term liabilities	426,470	528,738
Deferred tax liability	2,183,972	1,804,978
Total Liabilities	10,689,537	9,944,139
STOCKHOLDERS' EQUITY	7,362,823	6,174,323
TOTAL LIABILITIES & STOCKHOLDERS' EQUITY	$18,052,360	$16,118,462
COMMON SHARES OUTSTANDING	382,033	370,190

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF FIRST QUARTER 2006 ADDITIONS TO OIL AND NATURAL GAS PROPERTIES
($ in 000's, except per unit amounts)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe
Exploration and development costs	$615,338	272,544 (A)	$2.26
Acquisition of proved properties	453,051	243,080	1.86
Subtotal	1,068,389	515,624	2.07
Divestitures	(73)	(67)	---
Geological and geophysical costs	27,498	---	---
Adjusted subtotal	1,095,814	515,557	2.13
Revisions - price	---	(88,217)	---
Acquisition of unproved properties	545,738	---	---
Leasehold acquisition costs	172,553	---	---
Adjusted subtotal	1,814,105	427,340	4.25
Tax basis step-up	81,145	---	---
Asset retirement obligation and other	5,694	---	---
Total	$1,900,944	427,340	$4.45

(A) Includes positive performance revisions of 76 bcfe and excludes downward revisions of 88 bcfe resulting from oil and natural gas prices declines between December 31, 2005 and March 31, 2006.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
(unaudited)

	Mmcfe
Beginning balance, 12/31/05	7,520,690
Extensions and discoveries	196,769
Acquisitions	243,080
Divestitures	(67)
Revisions - performance	75,775
Revisions - price	(88,217)
Production	(136,752)
Ending balance, 3/31/06	7,811,278
Reserve replacement	427,340
Reserve replacement rate	312%

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

THREE MONTHS ENDED:	March 31, 2006	March 31, 2005
Oil and Natural Gas Sales ($ in thousands):		
Oil sales	$124,667	$79,944
Oil derivatives - realized gains (losses)	(3,808)	(7,067)
Oil derivatives - unrealized gains (losses)	(1,335)	(12,842)
Total Oil Sales	119,524	60,035
Natural gas sales	940,318	535,777
Natural gas derivatives - realized gains (losses)	252,029	47,415
Natural gas derivatives - unrealized gains (losses)	198,950	(104,285)
Total Natural Gas Sales	1,391,297	478,907
Total Oil and Natural Gas Sales	$1,510,821	$538,942
Average Sales Price (excluding gains (losses) on derivatives):		
Oil ($ per bbl)	$58.92	$45.79
Natural gas ($ per mcf)	$ 7.58	$ 5.69
Natural gas equivalent ($ per mcfe)	$ 7.79	$ 5.89
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Oil ($ per bbl)	$57.12	$41.74

Natural gas ($ per mcf)	$ 9.61	$ 6.20
Natural gas equivalent ($ per mcfe)	$ 9.60	$ 6.27

Interest Expense ($ in thousands)

Interest	$72,898	$47,293
Derivatives - realized (gains) losses	(1,244)	(1,121)
Derivatives - unrealized (gains) losses	1,004	(3,044)
Total Interest Expense	$72,658	$43,128

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

THREE MONTHS ENDED:	March 31, 2006	March 31, 2005
Cash provided by operating activities	$967,458	$512,685
Cash (used in) investing activities	(1,960,061)	(1,173,937)
Cash provided by financing activities	970,862	654,356

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
(in 000's)
(unaudited)

THREE MONTHS ENDED:	March 31, 2006	Dec. 31, 2005	March 31, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$967,458	$829,543	$512,685
Adjustments:			
Changes in assets and liabilities	79,405	3,250	(8,063)
OPERATING CASH FLOW*	$1,046,863	$832,793	$504,622

* 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 natural 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 natural 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:	March 31, 2006	Dec. 31, 2005	March 31, 2005
NET INCOME	$623,723	$452,525	$125,010
Income tax expense	382,283	260,114	71,856
Interest expense	72,658	64,177	43,128
Depreciation and amortization of other assets	23,872	16,175	10,082
Oil and natural gas depreciation, depletion and amortization	304,957	272,551	180,968
EBITDA**	$1,407,493	$1,065,542	$431,044

** 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:	March 31, 2006	Dec. 31, 2005	March 31, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$967,458	$829,543	$512,685
Changes in assets and liabilities	79,405	3,250	(8,063)
Interest expense	72,658	64,177	43,128
Unrealized gains (losses) on oil and natural gas derivatives	197,615	178,259	(117,127)
Other non-cash items	90,357	(9,687)	421
EBITDA	$1,407,493	$1,065,542	$431,044

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON
($ in 000's, except per share amounts)
(unaudited)

THREE MONTHS ENDED:	March 31, 2006	Dec. 31, 2005	March 31, 2005
Net income available to common shareholders	$603,902	$431,832	$119,547
Adjustments:			
Loss on conversion/exchange of preferred stock	1,009	4,406	---
Net Income	$604,911	$436,238	$119,547
Adjustments, net of tax:			
Unrealized (gains) losses on derivatives	(121,899)	(112,965)	72,443
Loss on repurchases or exchanges of debt	---	236	572
Early retirement expense	33,947	---	---
Gain on sale of investment	(72,786)	---	---
Adjusted net income available to common shareholders*	$444,173	$323,509	$192,562
Adjusted earnings per share assuming dilution**	$1.07	$0.84	$0.56

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

a. Management uses adjusted net income available to common to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.

b. Adjusted net income available to common are more comparable to earnings estimates provided by securities analysts.

c. Items excluded generally are one-time items, or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

** For purposes of calculating fully diluted shares and earnings per share assuming dilution for the three months ended March 31, 2006 and December 31, 2005, accounting rules prohibit the company from assuming the conversion of the 5.0% (Series 2003) and the 4.125% preferred stock for common shares prior to conversion or exchange 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 431.7 million and 404.8 million for the three months ended March 31, 2006 and December 31, 2005, respectively).

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EBITDA
($ in 000's)
(unaudited)

THREE MONTHS ENDED:	March 31, 2006	Dec. 31, 2005	March 31, 2005
EBITDA	$1,407,493	$1,065,542	$431,044
Adjustments, before tax:			
Unrealized (gains) losses on oil and natural gas derivatives	(197,615)	(178,259)	117,127
Loss on repurchases or exchanges of debt	---	372	900
Early retirement expense	54,753	---	---
Gain on sale of investment	(117,396)	---	---
Adjusted EBITDA*	$1,147,235	$887,655	$549,071

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

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

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF MAY 1, 2006

Quarter Ending June 30, 2006; Year Ending December 31, 2006; Year Ending December 31, 2007.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of May 1, 2006, we are using the following key assumptions in our projections for the second quarter of 2006, the full-year 2006 and the full-year 2007.

The primary changes from our February 23, 2006 Outlook are in italicized bold in the table and are explained as follows:

1) We have updated the projected effect of changes in our hedging positions since our February 23, 2006 Outlook.
2) We have updated our expectations for future NYMEX oil and natural gas prices based on current market conditions in order to illustrate

hedging effects only.

3) We have updated certain of our cost assumptions.

4) We have shown our projections for the quarter ending June 30, 2006 for the first time.

	Quarter Ending 6/30/2006	Year Ending 12/31/2006	Year Ending 12/31/2007
Estimated Production:			
Oil - mbbls	2,000	8,000	8,000
Natural gas - bcf	127 - 132	528 - 538	571 - 581
Natural gas equivalent - bcfe	139 - 144	576 - 586	619 - 629
Daily natural gas equivalent midpoint - in mmcfe	1,555	1,592	1,710
NYMEX Prices (A) (for calculation of realized hedging effects only):			
Oil - $/bbl	$60.00	$60.87	$50.00
Natural gas - $/mcf	$7.08	$7.52	$7.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	$1.33	$1.43	$7.83
Natural gas - $/mcf	$1.67	$2.02	$2.00
Estimated Differentials to NYMEX Prices:			
Oil - $/bbl	6 - 8%	6 - 8%	6 - 8%
Natural gas - $/mcf	8 - 12%	8 - 12%	8 - 12%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.85 - 0.95	$0.85 - 0.95	$0.90 - 1.00
Production taxes (generally 6.0% of O&G revenues) (B)	$0.48 - 0.53	$0.41 - 0.46	$0.36 - 0.41
General and administrative	$0.15 - 0.20	$0.15 - 0.20	$0.15 - 0.20
Stock-based compensation (non-cash)	$0.05 - 0.07	$0.06 - 0.08	$0.08 - 0.10
DD&A of oil and natural gas assets	$2.25 - 2.35	$2.30 - 2.35	$2.35 - 2.45
Depreciation of other assets	$0.16 - 0.20	$0.16 - 0.20	$0.20 - 0.25
Interest expense (C)	$0.52 - 0.57	$0.52 - 0.57	$0.53 - 0.58
Other Income per Mcfe:			
Marketing and other income	$0.02 - 0.04	$0.02 - 0.04	$0.02 - 0.04
Service operations income	$0.10 - 0.15	$0.10 - 0.15	$0.10 - 0.15
Book Tax Rate (approximately equal to 95% deferred)	38%	38%	38%
Equivalent Shares Outstanding:			
Basic	377 mm	376 mm	387 mm
Diluted	436 mm	436 mm	441 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$700 - 750 mm	$3,200 - 3,500 mm	$3,400 - 3,600 mm

(A) Oil NYMEX prices have been updated for actual contract prices through March 2006 and natural gas NYMEX prices have been updated for actual contract prices through April 2006.
(B) Severance tax per mcfe is based on NYMEX prices of $60.00 per bbl and natural gas prices ranging from $8.75 to $9.75 per mcf during Q2 2006, $7.35 to $8.35 per mcf during calendar 2006 and $50.00 per bbl and $6.50 to $7.50 per mcf during calendar 2007.
(C) 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 natural 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 natural 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 natural gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and natural 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 natural 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.

Excluding the swaps assumed in connection with the acquisition of CNR which are described below, the company currently has the following natural gas swaps in place:

	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 Natural Gas Production in Bcf's of:	% Hedged Open Swap Positions as a % of Estimated Total Natural Gas Production
2006:						
Q1	93.8	$10.81	-$0.09	$10.72	124.1	76%
Q2	101.4	$8.82	-$0.05	$8.77	129.5	78%
Q3	117.9	$8.80	-$0.05	$8.75	137.0	86%
Q4	114.9	$9.46	-$0.04	$9.42	142.4	81%
Total 2006(A)	428.0	$9.42	-$0.05	$9.37	533.0	80%
Total 2007	330.0	$9.94	-$0.04	$9.90	576.0	57%
Total 2008	248.9	$9.22	---	$9.22	604.0	41%
Total 2009	3.7	$9.02	---	$9.02	634.0	1%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 43.0 bcf in 2006.

Note: Not shown above are collars covering 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 2006 at a weighted average price of $12.50, 25.6 bcf of production in 2007 at a weighted average price of $10.53 and 7.3 bcf of production in 2008 at a weighed average price of $12.50.

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less*:	Volume in Bcf's	NYMEX plus*:
2006	130.1	$ 0.32	---	$ ---
2007	137.2	0.33	32.9	0.34
2008	118.6	0.27	25.6	0.34
2009	86.6	0.29	18.2	0.31
Totals	472.5	$ 0.30	76.7	$ 0.33

* weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($523 million as of March 31, 2006). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities", the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows.

The following details the CNR derivatives (natural gas swaps) we have assumed:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Assuming Natural Gas Production in Bcf's of:	% Hedged Open Swap Positions as a % of Estimated Total Natural Gas Production
2006:						
Q1	7.9	$4.91	$12.14	($7.23)	124.1	6%
Q2	10.5	$4.86	$9.97	($5.11)	129.5	8%
Q3	10.6	$4.86	$9.95	($5.09)	137.0	8%
Q4	10.6	$4.86	$10.38	($5.52)	142.4	7%
Total 2006	39.6	$4.87	$10.51	($5.64)	533.0	7%
Total 2007	42.0	$4.82	$9.18	($4.36)	576.0	7%
Total 2008	38.4	$4.67	$8.01	($3.34)	604.0	6%
Total 2009	18.3	$5.18	$7.28	($2.10)	634.0	3%

Note: Not shown above are collars covering 3.7 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00, respectively.

The company also has the following crude oil swaps in place:

	Open Swaps in mbbls	Avg. NYMEX Strike Price	Assuming Oil Production in mbbls of:	% Hedged Open Swap Positions as % of Total Estimated Production
2006:				
Q1	1,109.5	$60.03	2,116	52%

Q2	1,379.5	$61.85	2,000	69%
Q3	1,625.0	$63.90	1,942	84%
Q4	1,656.0	$63.76	1,942	85%
Total 2006(A)	5,770.0	$62.63	8,000	72%
Total 2007	3,555.0	$67.07	8,000	44%
Total 2008	2,928.0	$68.20	8,000	37%
Total 2009	182.5	$66.26	8,000	2%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $40.00 to $42.00 covering 501.5 mbbls in 2006.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF FEBRUARY 23, 2006
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF MAY 1, 2006

Quarter Ending March 31, 2006; Year Ending December 31, 2006; Year Ending December 31, 2007.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of February 23, 2006, we are using the following key assumptions in our projections for the first quarter of 2006, the full-year 2006 and the full- year 2007.

The primary changes from our January 17, 2006 Outlook are in italicized bold in the table and are explained as follows:

1) We have updated the projected effect of changes in our hedging positions since our January 17, 2006 Outlook.
2) We have updated our expectations for future NYMEX oil and gas prices based on current market conditions in order to illustrate hedging effects only.
3) We have updated the share count for the effect of accelerating the stock-based awards to our former Chief Operating Officer; however, we have not reflected the impact to stock-based compensation that will occur in the 2006 first quarter or full year.
4) We have not reflected the gain related to the sale of our investment in Pioneer Drilling Company in other income for the 2006 first quarter or full year.
5) We have updated the book tax rate for 2006 and 2007 primarily to account for the impact of state income taxes associated with our newly acquired Appalachian operations.

	Quarter Ending 3/31/2006	Year Ending 12/31/2006	Year Ending 12/31/2007
Estimated Production:			
Oil - Mbbl	1,900	7,700	7,750
Gas - Bcf	121 - 131	530 - 540	572 - 582
Gas Equivalent - Bcfe	132 - 142	576 - 586	619 - 629

Daily gas equivalent midpoint - in Mmcfe	1,522	1,593	1,709
NYMEX Prices (for calculation of realized hedging effects only):			
Oil - $/Bbl	$58.51	$54.00	$50.00
Gas - $/Mcf	$9.47	$7.99	$7.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/Bbl	$0.96	$4.51	$2.77
Gas - $/Mcf	$1.54	$1.40	$1.34
Estimated Differentials to NYMEX Prices:			
Oil - $/Bbl	6-8%	6-8%	6-8%
Gas - $/Mcf	10 - 15%	8 - 12%	8 - 12%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.77 - 0.82	$0.77 - 0.82	$0.80 - 0.85
Production taxes (generally 6.0% of O&G revenues) (A)	$0.48 - 0.53	$0.41 - 0.46	$0.36 - 0.41
General and administrative	$0.15 - 0.17	$0.14 - 0.16	$0.14 - 0.15
Stock-based compensation (non-cash)	$0.07 - 0.09	$0.08 - 0.10	$0.10 - 0.12
DD&A - oil and gas	$2.12 - 2.18	$2.15 - 2.20	$2.25 - 2.30
Depreciation of other assets	$0.14 - 0.16	$0.14 - 0.16	$0.14 - 0.16
Interest expense (B)	$0.52 - 0.57	$0.52 - 0.57	$0.53 - 0.58
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)	38%	38%	38%
Equivalent Shares Outstanding:			
Basic	368 mm	374 mm	381 mm
Diluted	431 mm	435 mm	440 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$650 - 700 mm	$3,000 - 3,200 mm	$3,300 - 3,500 mm

(A) Severance tax per mcfe is based on NYMEX prices of $58.51 per bbl and natural gas prices ranging from $9.00 to $10.00 per mcf during Q1 2006, $54.00 per bbl and $7.50 to $8.50 per mcf during calendar 2006 and $50.00 per bbl and $6.50 to $7.50 per mcf during calendar 2007.

(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.

Excluding the swaps assumed in connection with the acquisition of CNR which are described below, the company currently has in place the following natural gas swaps:

% Hedged
Open Swap
Avg. NYMEX Positions
Avg. NYMEX Gain Price Assuming as a % of
Strike (Loss) Including Gas Estimated
Price from Open & Production Total
Open Swaps Of Open Locked Locked in Gas
in Bcf's Swaps Swaps Positions Bcf's of: Production

2006:						
Q1	93.8	$10.81	-$0.09	$10.72	126.0	74%
Q2	96.9	$8.88	-$0.06	$8.82	132.0	73%
Q3	101.7	$8.93	-$0.06	$8.87	137.0	74%
Q4	90.0	$9.41	-$0.05	$9.36	140.0	64%
Total 2006(A)	382.4	$9.49	-$0.06	$9.43	535.0	71%
Total 2007	206.9	$9.91	-$0.06	$9.85	577.0	36%
Total 2008	131.8	$9.10	---	$9.10	604.0	22%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 43.0 bcf in 2006.

Note: Not shown above are collars covering 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 2006 at a weighted average price of $12.50, 25.6 bcf of production in 2007 at a weighted average price of $10.57 and 7.3 bcf of production in 2008 at a weighed average price of $12.50.

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
2006	130.1	$0.32	535	24%
2007	137.2	0.33	577	24%
2008	118.6	0.27	604	20%
2009	86.6	0.29	634	14%
Totals	472.5	$0.30	2,350	20%

* 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
2006:				
Q1	1,109.5	$60.03	1,900.0	58%
Q2	1,289.5	$61.13	1,920.0	67%
Q3	1,242.0	$61.50	1,940.0	64%
Q4	1,196.0	$61.33	1,940.0	62%
Total 2006(A)	4,837.0	$61.02	7,700.0	63%
Total 2007	1,730.0	$62.42	7,750.0	22%
Total 2008	1,098.0	$65.48	7,800.0	14%

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

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability as do other liabilities assumed in connection with the acquisition resulted in an increase in the total purchase price which is allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed will result in adjustments to our oil and gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and gas revenues related to the derivative positions. If, however, the actual sales price is different than the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we have hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities", the derivative instruments assumed in connection with the CNR acquisitions are deemed to contain a significant financing element and all cash flows associated with these positions will be reported as financing activity in the statement of cash flows.

The following details in the CNR derivatives (natural gas swaps) we have assumed:

						% Hedged
	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Assuming Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Gas Production
2006:						
Q1	7.9	$4.91	$12.14	($7.23)	126.0	6%
Q2	10.5	$4.86	$9.97	($5.11)	132.0	8%
Q3	10.6	$4.86	$9.95	($5.09)	137.0	8%
Q4	10.6	$4.86	$10.38	($5.52)	140.0	8%
Total 2006	39.6	$4.87	$10.51	($5.64)	535.0	7%
Total 2007	42.0	$4.82	$9.18	($4.36)	577.0	7%
Total 2008	38.4	$4.67	$8.01	($3.34)	604.0	6%
Total 2009	18.3	$5.18	$7.28	($2.10)	634.0	3%

Note: Not shown above are collars covering 3.7 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00, respectively.

SOURCE: Chesapeake Energy Corporation

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