NEWS RELEASE

Chesapeake Energy Corporation Reports Strong Results for the Fourth Quarter and Full-Year 2006

2006 Fourth Quarter Net Income Available to Common Shareholders Reaches $446 Million and Net Income per Fully Diluted Common Share Reaches $0.96 on Revenue of $1.9 Billion and Production of 152 Bcfe Full-Year 2006 Net Income Available to Common Shareholders Reaches $1.9 Billion on Revenue of $7.3 Billion and Production of 578 Bcfe; Full-Year 2006 Net Income of $4.35 per Fully Diluted Common Share Increases 73% Over Full-Year 2005 Proved Reserves Reach Record Level of 9.0 Tcfe; Company Delivers Full-Year Reserve Replacement Rate of 348% From 1.4 Tcfe of Additions at a Drilling and Acquisition Cost of $1.93 per Mcfe Company Provides Updated and Detailed Review of its 17.7 Tcfe of Risked Unproved Reserves Located on its 10.7 Million Net Acres of U.S. Onshore Leasehold

OKLAHOMA CITY--(BUSINESS WIRE)--Feb. 22, 2007--Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operating results for the 2006 fourth quarter and for the full-year 2006. For the quarter, Chesapeake generated net income available to common shareholders of $446 million ($0.96 per fully diluted common share), operating cash flow of $1.095 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.253 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.868 billion and production of 152 billion cubic feet of natural gas equivalent (bcfe). For the quarter, ebitda increased 18% over the 2005 fourth quarter and net income per fully diluted common share decreased 14%.

For the full-year 2006, Chesapeake generated net income available to common shareholders of $1.904 billion ($4.35 per fully diluted common share), operating cash flow of $4.045 billion and ebitda of $5.019 billion on revenue of $7.326 billion and production of 578 bcfe. Full-year 2006 ebitda and net income per fully diluted common share increased 89% and 73%, respectively, over the full-year 2005.

Excluding the items detailed below, Chesapeake generated adjusted net income to common shareholders in the 2006 fourth quarter of $418 million ($0.90 per fully diluted common share) and adjusted ebitda of $1.210 billion. For the full-year 2006, Chesapeake generated adjusted net income to common shareholders of $1.575 billion ($3.61 per fully diluted common share) and adjusted ebitda of $4.449 billion. For the 2006 fourth quarter, adjusted ebitda and adjusted net income per fully diluted common share increased 36% and 7%, respectively, over the 2005 fourth quarter. For the full-year 2006, adjusted ebitda and adjusted net income per fully diluted common share increased 66% and 40%, respectively, over the full-year 2005. The excluded items do not affect the calculation of operating cash flow.

The company's fourth quarter and full-year 2006 net income available to common shareholders and ebitda include various items that are typically not included in published estimates of the company's financial results by certain securities analysts. Such items and their after-tax effects on fourth quarter and full-year reported results are described as follows:

-- an unrealized mark-to-market gain of $27 million for the fourth quarter and a $308 million gain for the full-year resulting from the company's oil and natural gas and interest rate hedging programs;

-- a realized gain of $73 million for the full-year resulting from the sale of the company's investment in the common stock of Pioneer Drilling Corporation (AMEX:PDC);

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

-- a reversal of an accrual for the full-year of $7 million for production taxes as a result of the dismissal of certain production tax claims;

-- a $15 million income tax accrual for the full-year relating to the adoption of a "margin" tax in Texas; and

-- a reduction of net income available to common shareholders of $11 million for the full-year resulting from exchanges of the company's preferred stock for common stock.

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 21-24 of this release.

Key Operational and Financial Statistics Summarized Below for the 2006 Fourth Quarter, 2006 Third Quarter, 2005 Fourth Quarter and for the Full-Years 2006 and 2005

The table below summarizes Chesapeake's key results during the 2006 fourth quarter and compares them to the 2006 third quarter and the 2005 fourth quarter and also compares the 2006 full-year to the 2005 full-year.

	Three Months Ended:			Full-Year Ended:	
	12/31/06	9/30/06	12/31/05	12/31/06	12/31/05
Average daily production (in mmcfe)	1,653	1,597	1,418	1,585	1,284
Natural gas as % of total production	91	91	91	91	90
Natural gas production (in bcf)	138.8	133.8	118.3	526.5	422.4
Average realized natural gas price ($/mcf) (a)	9.03	8.39	8.08	8.76	6.78
Oil production (in mbbls)	2,217	2,178	2,014	8,654	7,698
Average realized oil price ($/bbl) (a)	59.95	60.62	52.65	59.14	47.77
Natural gas equivalent production (in bcfe)	152.1	146.9	130.4	578.4	468.6
Natural gas equivalent realized price ($/mcfe) (a)	9.11	8.54	8.14	8.86	6.90
Oil and natural gas marketing income ($/mcfe)	.11	.09	.10	.09	.07
Service operations income ($/mcfe)	.09	.13	-	.11	-
Production expenses ($/mcfe)	(.82)	(.84)	(.72)	(.85)	(.68)
Production taxes ($/mcfe)	(.31)	(.28)	(.55)	(.31)	(.44)
General and administrative costs ($/mcfe) (b)	(.22)	(.20)	(.15)	(.19)	(.10)
Stock-based compensation ($/mcfe)	(.04)	(.06)	(.04)	(.05)	(.03)
DD&A of oil and natural gas properties ($/mcfe)	(2.51)	(2.34)	(2.09)	(2.35)	(1.91)
D&A of other assets ($/mcfe)	(.20)	(.18)	(.12)	(.18)	(.11)
Interest expense ($/mcfe) (a)	(.54)	(.52)	(.49)	(.52)	(.47)
Operating cash flow ($					

in millions) (c)	1,095.5	988.6	832.8	4,045.1	2,425.7
Operating cash flow ($/mcfe)	7.20	6.73	6.39	6.99	5.18
Adjusted ebitda ($ in millions) (d)	1,209.7	1,090.7	887.7	4,449.1	2,687.5
Adjusted ebitda ($/mcfe)	7.96	7.43	6.81	7.69	5.74
Net income to common shareholders ($ in millions)	445.5	522.6	431.8	1,904.1	879.6
Earnings per share - assuming dilution ($)	0.96	1.13	1.11	4.35	2.51
Adjusted net income to common shareholders ($ in millions) (e)	418.4	373.1	323.5	1,575.4	924.1
Adjusted earnings per share - assuming dilution ($)	0.90	0.83	0.84	3.61	2.57

(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 net income before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on pages 23 and 24

(e) defined as net income available to common shareholders, as adjusted to remove the effects of certain items detailed on pages 23 and 24

Oil and Natural Gas Production Sets Record for 22nd Consecutive Quarter and 17th Consecutive Year; 2006 Fourth Quarter Average Daily Production Increases 17% over the 2005 Fourth Quarter and Full-Year 2006 Production Increases 23% over Full-Year 2005

Daily production for the 2006 fourth quarter averaged 1.653 bcfe, an increase of 235 million cubic feet of natural gas equivalent (mmcfe), or 17%, over the 1.418 bcfe of daily production in the 2005 fourth quarter and an increase of 56 mmcfe, or 4%, over the 1.597 bcfe produced per day in the 2006 third quarter. During October 2006, Chesapeake elected to defer approximately 2.0 billion cubic feet of natural gas (bcf) of production in response to temporarily depressed natural gas prices.

Chesapeake's 2006 fourth quarter production of 152.1 bcfe was comprised of 138.8 bcf (91% on a natural gas equivalent basis) and 2.22 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 1.653 bcfe consisted of 1.508 bcf of natural gas and 24,098 barrels (bbls) of oil. The 2006 fourth quarter was Chesapeake's 22nd consecutive quarter of sequential U.S. production growth. Over these 22 quarters, Chesapeake's U.S. production has increased 322%, for an average compound quarterly growth rate of 6.8% and an average compound annual growth rate of 29.7%.

The company's daily production for the full-year 2006 averaged 1.585 bcfe, an increase of 301 mmcfe, or 23%, over the 1.284 bcfe of daily production for the full-year 2005. Chesapeake's full-year 2006 production of 578.4 bcfe was comprised of 526.5 bcf (91% on a natural gas equivalent basis) and 8.65 mmbbls (9% on a natural gas equivalent basis). Chesapeake's average daily production for the full-year 2006 of 1.585 bcfe consisted of 1.442 bcf of natural gas and 23,710 bbls of oil. The full-year 2006 was Chesapeake's 17th consecutive year of sequential production growth.

Chesapeake's 23% total production growth in 2006 follows growth of 29% in 2005, 35% in 2004, 48% in 2003 and 12% in 2002. The company's current rate of production is approximately 1.7 bcfe per day and based on projected drilling levels and anticipated results, Chesapeake is forecasting total production growth of 14-18% for 2007 and 10-14% for 2008.

Year-End 2006 Oil and Natural Gas Proved Reserves Reach Record Level of 9.0 Tcfe; Full-Year 2006 Drilling and Acquisition Costs Average $1.93 per Mcfe as Company Added 1.4 Tcfe for a Reserve Replacement Rate of 348%

Chesapeake began 2006 with estimated proved reserves of 7.521 trillion cubic feet of natural gas equivalent (tcfe) and ended the year with 8.956 tcfe, an increase of 1.435 tcfe, or 19%. During 2006, Chesapeake replaced its 578 bcfe of production with an estimated 2.013 tcfe of new proved reserves for a reserve replacement rate of 348%. Reserve replacement through the drillbit was 1.345 tcfe, or 233% of production (including 729 bcfe of positive performance revisions and 212 bcfe of downward revisions resulting from oil and natural gas price declines between December 31, 2005 and December 31, 2006) and 67% of the total increase. Reserve replacement through the acquisition of proved reserves was 668 bcfe, or 115% of production and 33% of the total increase.

On a per thousand cubic feet of natural gas equivalent (mcfe) basis, the company's total drilling and acquisition costs were $1.93 per mcfe (excluding costs of $154 million for seismic, $3.472 billion for unproved properties and leasehold acquired during the period and $203 million relating to tax basis step-up and asset retirement obligations, as well as downward revisions of proved reserves from lower natural gas prices). Excluding these items described above, Chesapeake's exploration and development costs through the drillbit were $2.00 per mcfe during 2006 while reserve replacement costs through acquisitions of proved reserves were $1.76 per mcfe. Total costs incurred in oil and natural gas acquisition, exploration and development during the full-year 2006, including seismic, leasehold, unproved properties, capitalized internal costs, non-cash tax basis step-up from corporate acquisitions and asset retirement obligations, were $8.126 billion. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 19 of this release.

During 2006, Chesapeake continued the industry's most active drilling program and drilled 1,488 gross (1,243 net) operated wells and participated in another 1,534 gross (206 net) wells operated by other companies. The company's drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2006, Chesapeake invested $2.636 billion in operated wells (using an average of 98 operated rigs), $502 million in non-operated wells (using an average of 79 non-operated rigs), $617 million to acquire new leasehold (exclusive of $2.856 billion in unproved leasehold obtained through corporate and asset acquisitions) and $154 million to acquire 3-D seismic data.

As of December 31, 2006, Chesapeake's estimated future net cash flows discounted at an annual rate of 10% before income taxes (PV-10) and after income taxes (standardized measure) from its proved reserves were $13.6 billion and $10.0 billion, respectively, using field differential adjusted prices of $56.25 per barrel of oil (bbl) (based on a NYMEX year-end price of $61.15 per bbl) and $5.41 per thousand cubic feet of natural gas (mcf) (based on a NYMEX year-end price of $5.64 per mcf). Chesapeake's PV-10 changes by approximately $350 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.

By comparison, the December 31, 2005 PV-10 and standardized measure of the company's proved reserves were $22.9 billion and $16.0 billion, respectively, using field differential adjusted prices of $56.41 per bbl (based on a NYMEX year-end price of $61.11 per bbl) and $8.76 per mcf (based on a NYMEX year-end price of $10.08 per mcf).

In addition to the PV-10 value of its proved reserves, the net book value of the company's other assets (including drilling rigs, land and buildings, investments in companies, securities, long-term derivative instruments and other non-current assets) was $2.8 billion as of December 31, 2006 and $1.3 billion as of December 31, 2005.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2006 fourth quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $59.95 per bbl and $9.03 per mcf, for a realized natural gas equivalent price of $9.11 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the fourth quarter were a negative $5.14 per bbl and a negative $0.67 per mcf. Realized gains from oil and natural gas hedging activities during the quarter generated a $4.88 gain per bbl and a $3.14 gain per mcf, for a 2006 fourth quarter realized hedging gain of $447 million, or $2.94 per mcfe.

For the full-year 2006, average prices realized were $59.14 per bbl and $8.76 per mcf, for a realized natural gas equivalent price of $8.86 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the full-year were a negative $5.36 per bbl and a negative $0.89 per mcf. Realized gains and losses from oil and natural gas hedging activities during the full-year generated a $1.72 loss per bbl and a $2.41 gain per mcf, for a full-year 2006 realized hedging gain of $1.254 billion, or $2.17 per mcfe.

After lifting a portion of its 2007-2009 hedges during periods of natural gas price weakness in the past six months and securing gains of approximately $738 million, the company has recently reestablished most of these hedges at equally attractive prices.

The following tables compare Chesapeake's hedged production volumes through swaps and collars as of February 22, 2007 to those previously announced as of February 5, 2007. Additionally, the gains from lifted natural gas hedges are presented as of February 22, 2007. 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.

Open Swap Positions as of February 22, 2007

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2007 1Q	32%	9.71	56%	71.98
2007 2Q	50%	8.06	60%	72.12
2007 3Q	54%	8.23	60%	71.89
2007 4Q	54%	8.95	60%	71.61
2007 Total	48%	8.63	59%	71.90
2008 Total	60%	9.20	51%	71.63
2009 Total	7%	9.00	2%	66.10

Open Natural Gas Collar Positions as of February 22, 2007

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2007 1Q	N/A	N/A	N/A
2007 2Q	15%	6.76	8.20
2007 3Q	14%	6.76	8.20
2007 4Q	11%	7.13	8.88
2007 Total	10%	6.88	8.41
2008 Total	3%	7.38	9.20

Gains From Lifted Natural Gas Hedges as of February 22, 2007

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2007 1Q	281	139	2.02
2007 2Q	114	147.5	0.77
2007 3Q	104	159	0.65
2007 4Q	116	173.5	0.67
2007 Total	615	619	0.99
2008 Total	105	701	0.15
2009 Total	4	750	0.01

Additionally, the company has lifted a portion of its oil hedges during periods of oil price weakness in the past six months, securing gains of $8.8 million and $4.8 million in 2007 and 2008, respectively.

Open Swap Positions as of February 5, 2007

Quarter or Year	Natural Gas % Hedged	Natural Gas $ NYMEX	Oil % Hedged	Oil $ NYMEX
2007 1Q	31%	9.71	56%	71.98
2007 2Q	44%	8.07	60%	72.12
2007 3Q	48%	8.24	60%	71.89
2007 4Q	52%	8.96	60%	71.61
2007 Total	44%	8.67	59%	71.90
2008 Total	56%	9.22	50%	71.63

Open Natural Gas Collar Positions as of February 5, 2007

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2007 1Q	N/A	N/A	N/A
2007 2Q	15%	6.76	8.20
2007 3Q	14%	6.76	8.20
2007 4Q	12%	7.13	8.88
2007 Total	10%	6.88	8.41
2008 Total	3%	7.38	9.20

Certain open natural gas swap positions include "knockout" provisions at prices ranging from $5.25 to $6.50 covering 146 bcf in 2007, $5.75 to $6.50 covering 160 bcf in 2008 and $5.90 to $6.25 covering 36 bcf in 2009, and certain open natural gas collar positions include "knockout" provisions at prices ranging from $5.00 to $6.00 covering 52 bcf in 2007 and $5.00 to $6.00 covering 11 bcf in 2008. Also, certain open oil swap positions include "knockout" provisions at prices ranging from $45.00 to $60.00 covering 1.5 mmbbls in 2007 and 1.1 mmbbls in 2008.

Combining the company's 2006 realized hedging gains, the 2007-2009 gains from lifted hedges that will be recognized in the periods for which production was originally hedged and the approximate $525 million of current mark-to-market value of open hedges, management has created $2.5 billion of value for shareholders from Chesapeake's 2006 full-year and 2007 to-date hedging activities. These best-in-the-industry results further demonstrate Chesapeake's ability to create value and achieve substantial risk mitigation through its hedging programs.

The company's updated forecasts for 2007 and 2008 are attached to this release in an Outlook dated February 22, 2007 labeled as Schedule "A", which begins on page 26. This Outlook has been changed from the Outlook dated December 11, 2006 (attached as Schedule "B", which begins on page 30) to reflect various updated information.

Balance Sheet and Credit Quality Further Improved in 2006

As of December 31, 2006, Chesapeake's long-term debt was $7.376 billion and its stockholders' equity was $11.251 billion, for a debt-to-total capitalization ratio of 40%, compared to a debt-to-total capitalization ratio of 47% at year-end 2005. At year-end 2006, the company's long-term debt to adjusted ebitda ratio was 1.7x compared to a long-term debt to adjusted ebitda ratio of 2.0x at year-end 2005. After attributing $1.0 billion of the company's long-term debt to non-oil and natural gas assets that have a current book value of $2.8 billion, Chesapeake's long-term debt per mcfe of proved reserves at year-end 2006 was $0.71. This compares to $0.66 per mcfe at year-end 2005 after attributing $500 million of the company's long-term debt to the company's year-end 2005 non-oil and natural gas assets that had a book value of $1.3 billion.

Chesapeake's Leasehold and 3-D Seismic Inventories Now Total 10.7 Million Net Acres and 16.3 Million Acres; Risked Unproved Reserves in the Company's Inventory Now Reach 17.7 Tcfe, Bringing Total Reserve Base to 26.7 Tcfe

Since 2000, Chesapeake has invested $6.6 billion in new leasehold and 3-D seismic acquisitions and now owns one of the largest inventories of onshore leasehold (10.7 million net acres) and 3-D seismic (16.3 million acres) in the U.S. On this leasehold, the company has approximately 26,000 net drilling locations, representing an approximate 10-year inventory of drilling projects, on which it believes it can develop an estimated 3.4 tcfe of proved undeveloped reserves and approximately 17.7 tcfe of risked unproved reserves (71 tcfe of unrisked unproved reserves). Chesapeake's 9.0 tcfe of proved reserves and its 17.7 tcfe of risked unproved reserves total approximately 26.7 tcfe.

To aggressively develop these assets, Chesapeake has continued to significantly strengthen its technical capabilities by increasing its land, geoscience and engineering staff to approximately 1,000 employees. Today, the company has approximately 5,000 employees, of which approximately 60% work in the company's E&P operations and approximately 40% 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 unconventional 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 unproved reserves associated with such drillsites. The following summarizes Chesapeake's ownership and activity in each gas resource play type and highlights notable projects in each play.

Conventional Gas Resource Plays - In its traditional conventional areas (i.e., portions of the Mid-Continent, Permian, Gulf Coast and South Texas regions), where exploration targets are typically deep and defined using 3-D seismic data, Chesapeake believes it has a meaningful competitive advantage due to its operating scale, deep drilling expertise and over 13.3 million acres of 3-D seismic data. In these plays, Chesapeake owns 3.2 million net acres on which it has an estimated 1.0 tcfe of proved undeveloped reserves and approximately 3.1 tcfe of risked unproved reserves and is currently using 35 operated drilling rigs to further develop its inventory of approximately 3,500 drillsites. Three of Chesapeake's most important conventional gas resource plays are described below:

-- Southern Oklahoma (generally Pennsylvanian-aged formations in Bray, Cement, Golden Trend, Sholem Alechem and Texoma): From various formations located in the Marietta, Ardmore and Anadarko Basins, the company is producing approximately 155 mmcfe net per day. The company is currently using 10 operated rigs and plans to drill approximately 36 net wells in 2007 to further develop its 390,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in southern Oklahoma are an estimated 238 bcfe and its risked unproved reserves are approximately 800 bcfe after applying a 75% risk factor and assuming an additional 600 net wells are drilled in the years ahead. The company's targeted results for southern Oklahoma wells are $3.5 million to develop 2.2 bcfe on approximately 120 acre spacing.

-- South Texas: Located primarily in Zapata County, Texas, Chesapeake's South Texas assets are producing approximately 150 mmcfe net per day. The company is currently using six operated rigs and plans to drill approximately 50 net wells in 2007 to further develop its 160,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in South Texas are an estimated 174 bcfe and its risked unproved reserves are approximately 340 bcfe after applying a 75% risk factor and assuming an additional 390 net wells are drilled in the years ahead. The company's targeted results for vertical South Texas wells are $2.8 million to develop 1.8 bcfe on approximately 80 acre spacing.

-- Mountain Front (primarily Morrow and Springer formations in western Oklahoma): From these prolific formations located in the Anadarko Basin, the company is producing approximately 100 mmcfe net per day. The company is currently using four operated rigs and plans to drill approximately five net wells in 2007 to further develop its 130,000 net acres of Mountain Front leasehold. Chesapeake's proved undeveloped reserves in the Mountain Front are an estimated 55 bcfe and its risked unproved reserves are approximately 200 bcfe after applying a

70% risk factor and assuming an additional 85 net wells are drilled in the years ahead. The company's targeted results for vertical Mountain Front wells are $8.0 million to develop 4.0 bcfe on approximately 320 acre spacing.

Unconventional Gas Resource Plays - In its unconventional gas resource areas, Chesapeake owns 1.3 million net acres on which it has an estimated 1.8 tcfe of proved undeveloped reserves and approximately 6.6 tcfe of risked unproved reserves and is currently using 67 operated drilling rigs to further develop its inventory of approximately 9,800 net drillsites. Four of Chesapeake's most important unconventional gas resource plays are described below:

-- Fort Worth Barnett Shale (North Texas): The Fort Worth Barnett Shale is the largest and most prolific unconventional gas resource play in the U.S. In this play, Chesapeake is the fourth largest producer of natural gas, the most active driller and the largest leasehold owner in the Tier 1 sweet spot of Tarrant, Johnson and western Dallas counties. Chesapeake is producing approximately 175 mmcfe net per day from the Fort Worth Barnett Shale. The company is currently using 24 operated rigs and plans to drill approximately 320 net wells in 2007 to further develop its 190,000 net acres of leasehold, of which 160,000 net acres are located in the Tier 1 area. By mid-year, Chesapeake expects to be using 30-35 operated rigs in the play and to be completing, on average, one new Barnett Shale well every day. Chesapeake's proved undeveloped reserves in the Fort Worth Barnett are an estimated 642 bcfe and its risked unproved reserves are approximately 3.5 tcfe after applying a 15% risk factor and assuming an additional 2,300 net wells are drilled in the years ahead. The company's targeted results for Tier 1 horizontal Fort Worth Barnett Shale wells are $2.5 million to develop 2.45 bcfe on approximately 60 acre spacing utilizing wellbores that are generally 3,000' in length and 500' apart. Chesapeake's targeted results for Tier 2 horizontal Fort Worth Barnett Shale wells are $2.25 million to develop 1.5 bcfe.

-- Sahara (primarily Mississippi, Chester, Hunton formations in Northwest Oklahoma): In this vast play that extends across five counties in northwestern Oklahoma, Chesapeake is the largest producer of natural gas, the most active driller and the largest leasehold owner in the area. Chesapeake is producing approximately 145 mmcfe net per day in the Sahara area. The company is currently using 15 operated rigs and plans to drill approximately 330 net wells in 2007 to further develop its 600,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in Sahara are an estimated 437 bcfe and its risked unproved reserves are approximately 2.3 tcfe after applying a 25% risk factor and assuming an additional 5,700 net wells are drilled in the years ahead. The company's targeted results for vertical Sahara wells are $0.9 million to develop 0.6 bcfe on approximately 65 acre spacing.

-- Ark-La-Tex Tight Gas Sands (primarily Travis Peak, Cotton Valley, Pettit and Bossier formations): In this large region covering most of East Texas and northern Louisiana, Chesapeake has assembled a strong portfolio of unconventional gas resource plays. Chesapeake is one of the ten largest producers of natural gas, the third most active driller and one of the largest leasehold owners in the area. Chesapeake is producing approximately 115 mmcfe net per day in the Ark-La-Tex area. The company is currently using 15 operated rigs and plans to drill approximately 125 net wells in 2007 to further develop its 210,000 net acres of leasehold. Chesapeake's unconventional proved undeveloped reserves in the Ark-La-Tex region are an estimated 318 bcfe and its unconventional risked unproved reserves are approximately 300 bcfe after applying a

70% risk factor and assuming an additional 800 net wells are drilled in the years ahead. The company's targeted results for medium-depth vertical Ark-La-Tex wells are $1.7 million to develop 1.0 bcfe on approximately 60 acre spacing.

-- Granite, Atoka and Colony Washes (western Oklahoma and Texas Panhandle): Chesapeake is the largest producer of natural gas, the most active driller and the largest leasehold owner in the Wash plays in the Anadarko Basin. Chesapeake is producing approximately 115 mmcfe net per day from these plays. The company is currently using 12 operated rigs and plans to drill approximately 40 net wells in 2007 to further develop its 130,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Wash plays are an estimated 361 bcfe and its risked unproved reserves are approximately 300 bcfe after applying a 50% risk factor and assuming an additional 600 net wells are drilled in the years ahead. The company's targeted results for vertical Wash wells are $2.8 million to develop 1.4 bcfe on approximately 80 acre spacing.

Emerging Unconventional Gas Resource Plays - In its emerging unconventional gas resource areas where commercial production has only recently been established but the future reserve potential could be substantial, Chesapeake owns 2.7 million net acres on which it has approximately 100 bcfe of proved undeveloped reserves and approximately 5.6 tcfe of risked unproved reserves and is currently using 19 operated drilling rigs to further develop its inventory of approximately 3,300 net drillsites. Five of Chesapeake's most important emerging unconventional gas resource plays are described below:

-- Fayetteville Shale (Arkansas): In this region of growing importance to Chesapeake, the company is the largest leasehold owner in the play (second largest in the core area of the play). Chesapeake is producing approximately 10 mmcfe net per day from the Fayetteville Shale. The company is currently using three operated rigs and will gradually increase its drilling activity level to 12 operated rigs by mid-year 2007 in order to drill approximately 110 net wells in 2007 to further develop its 350,000 net acres of leasehold in the core area of the play. Chesapeake's proved undeveloped reserves in the Fayetteville core area are an estimated 41 bcfe and its risked unproved reserves are approximately 2.9 tcfe after applying a 50% risk factor to its core area acreage and assuming an additional 2,200 net wells are drilled in the years ahead. The company's targeted results for horizontal core area Fayetteville Shale wells are $2.9 million to develop 1.6 bcfe on approximately 80 acre spacing. The company is currently risking its 700,000 net acres of non-core area leasehold at 100%.

-- Deep Haley (primarily Strawn, Atoka, Morrow formations in West Texas): In this West Texas Delaware Basin area the company is the second largest leasehold owner and the second most active driller. Chesapeake is producing approximately 30 mmcfe net per day from the Deep Haley area. The company is currently using seven operated rigs and plans to drill approximately 17 net wells in 2007 to further develop its 260,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in Deep Haley are an estimated 45 bcfe and its risked unproved reserves are approximately 800 bcfe after applying a 75% risk factor and assuming an additional 200 net wells are drilled in the years ahead. The company's targeted results for vertical Deep Haley wells are $12.0 million to develop 6.0 bcfe on approximately 320 acre spacing.

-- Delaware Basin Shales (primarily Barnett and Woodford formations in West Texas): Chesapeake's most significant land acquisition activities during 2006 took place in the Delaware Basin Barnett and Woodford Shale plays in far West Texas where Chesapeake is now the largest leasehold owner. The company is producing approximately 1.0 mmcfe net per day from the Delaware Basin Barnett and Woodford Shales. The company is currently using six operated rigs and plans to drill approximately 25 net wells in 2007 to further develop its 670,000 net acres of leasehold. Chesapeake has not yet booked any proved undeveloped reserves in the Delaware Basin shales play although its risked unproved reserves are an estimated 1.0 tcfe after applying a 90% risk factor and assuming an additional 400 net wells are drilled in the years ahead. The company's targeted results for Delaware Basin vertical Barnett and Woodford Shale wells are $4.5 million to develop 3.0 bcfe on approximately 160 acre spacing. The company has not yet developed a model for targeted results from horizontal wells in the play.

-- Woodford Shale (southeastern Oklahoma Arkoma Basin): Chesapeake is the second largest leasehold owner in the Woodford Shale play, an unconventional gas play in the southeastern Oklahoma portion of the Arkoma Basin. The company is producing approximately 10 mmcfe net per day from the Woodford Shale. The company is currently using two operated rigs and plans to drill approximately 20 net horizontal Woodford Shale wells in 2007 to further develop its 100,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the play are an estimated 15 bcfe and its risked unproved reserves are approximately 500 bcfe after applying a 50% risk factor and assuming an additional 300 net wells are drilled in the years ahead. The company's targeted results for horizontal Woodford Shale wells are $4.0 million to develop 2.2 bcfe on approximately 160 acre spacing.

-- Deep Bossier (East Texas and northern Louisiana): Chesapeake is one of the top three leasehold owners in the Deep Bossier play. The company is producing approximately 1.0 mmcfe net per day in the Deep Bossier play. The company plans to drill approximately five net wells in 2007 to further develop its 260,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Deep Bossier play are an estimated 2 bcfe and its risked unproved reserves are approximately 300 bcfe after applying a 90% risk factor and assuming an additional 80 net wells are drilled in the years ahead. The company's targeted results for Deep Bossier wells are $10.0 million to develop 5.0 bcfe on approximately 320 acre spacing.

Appalachian Basin Gas Resource Plays - In this newest core area of the company's operations, play types include conventional, unconventional and emerging unconventional in the Devonian Shale and other formations. Chesapeake is the largest leasehold owner in the region with 3.5 million net acres. The company is producing approximately 130 mmcfe net per day. The company is currently using 11 operated rigs and plans to drill approximately 375 net wells in 2007 to further develop its extensive leasehold position. In Appalachia, Chesapeake has an estimated 533 bcfe of proved undeveloped reserves and its risked unproved reserves are approximately 2.4 tcfe after applying a 35% risk factor and assuming an additional 9,000 net wells are drilled in the years ahead. The company's targeted results for vertical Devonian Shale wells are $0.5 million to develop 0.35 bcfe on approximately 160 acre spacing.

In addition, Chesapeake continues to actively generate new prospects and acquire additional leasehold throughout the company's areas of operation in various conventional, unconventional and emerging unconventional plays not described above.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report outstanding financial and operational results for the 2006 fourth quarter and full-year. The company delivered attractive production and reserve growth and generated impressive profit margins at the top of our large-cap peer group that were enhanced by the company's well-executed hedging strategy. Our focused business strategy, value-added growth, tremendous inventory of undrilled locations and valuable hedge positions clearly differentiate Chesapeake in the industry.

In light of continued strong returns available through the drillbit on our extensive prospect inventory, we have increased our industry-leading U.S. drilling activity to accelerate development of our substantial proved undeveloped and unproved reserve base. We currently have 132 operated rigs working, up from an average of 73 operated rigs in 2005 and an average of 123 operated rigs in the 2006 fourth quarter. We anticipate keeping our operated rig count between 130 and 140 rigs during 2007.

Our business strategy continues to feature 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 equity and mitigating financial and operational risks through opportunistic hedging. 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 to discuss this release has been scheduled for Friday morning, February 23, 2007 at 9:00 a.m. EST. The telephone number to access the conference call is 913-981-5543 and the confirmation code is 5800842. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 am EST. For those unable to participate in the conference call, a replay will be available for audio playback from noon EST, February 23, 2007 through midnight EST on March 9, 2007. The number to access the conference call replay is 719-457-0820 and the passcode for the replay is 5800842. The conference call will also be webcast live on the Internet and can be accessed by going to Chesapeake's website at www.chkenergy.com and selecting the "News & Events" section. The webcast of the conference call will be available on our website for one year.

This press release and the accompanying Outlooks include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of 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. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in the Prospectus Supplement dated December 8, 2006 for our offering of common stock filed with the Securities and Exchange Commission on December 8, 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.

Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties.

The SEC has generally permitted oil and 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 term "unproved" to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

Chesapeake Energy Corporation is the 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 corporate and property acquisitions in the Mid-Continent, Fort Worth Barnett Shale, Appalachian Basin, Fayetteville Shale, South Texas, Permian Basin, Delaware Basin, Ark-La-Tex and Texas Gulf Coast regions of the United States. The company's Internet address is www.chkenergy.com.

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

THREE MONTHS ENDED:	December 31, 2006		December 31, 2005	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	1,428,464	9.39	1,240,314	9.51
Oil and natural gas marketing sales	406,300	2.67	510,665	3.92
Service operations revenue	32,837	0.22	--	--
Total Revenues	1,867,601	12.28	1,750,979	13.43
OPERATING COSTS:				
Production expenses	125,365	0.82	94,296	0.72
Production taxes	46,582	0.31	71,585	0.55
General and administrative expenses	39,424	0.26	24,632	0.19
Oil and natural gas marketing expenses	390,327	2.57	497,214	3.82
Service operations expense	18,997	0.12	--	--
Oil and natural gas depreciation, depletion and amortization	381,680	2.51	272,551	2.09
Depreciation and amortization of other assets	30,189	0.20	16,175	0.12
Total Operating Costs	1,032,564	6.79	976,453	7.49
INCOME FROM OPERATIONS	835,037	5.49	774,526	5.94

OTHER INCOME (EXPENSE):				
Interest and other income	5,721	0.04	2,662	0.02
Interest expense	(80,496)	(0.53)	(64,177)	(0.49)
Gain on sale of investment	--	--	--	--
Loss on repurchases or exchanges of senior notes	--	--	(372)	(0.01)
Total Other Income (Expense)	(74,775)	(0.49)	(61,887)	(0.48)
INCOME BEFORE INCOME TAXES	760,262	5.00	712,639	5.46
Income Tax Expense:				
Current	5,000	0.03	--	--
Deferred	283,900	1.87	260,114	1.99
Total Income Tax Expense	288,900	1.90	260,114	1.99
NET INCOME	471,362	3.10	452,525	3.47
Preferred stock dividends	(25,852)	(0.17)	(16,287)	(0.13)
Loss on exchange/conversion of preferred stock	--	--	(4,406)	(0.03)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	445,510	2.93	431,832	3.31
EARNINGS PER COMMON SHARE:				
Basic	$1.05		$1.25	
Assuming dilution	$0.96		$1.11	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)				
Basic	426,233		344,614	
Assuming dilution	491,000		403,730	

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

TWELVE MONTHS ENDED:	December 31, 2006		December 31, 2005	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	5,618,894	9.71	3,272,585	6.98
Oil and natural gas marketing sales	1,576,391	2.73	1,392,705	2.97
Service operations revenue	130,310	0.23	--	--
Total Revenues	7,325,595	12.67	4,665,290	9.95
OPERATING COSTS:				
Production expenses	489,499	0.85	316,956	0.68
Production taxes	176,440	0.31	207,898	0.44
General and administrative expenses	139,152	0.24	64,272	0.14
Oil and natural gas marketing expenses	1,521,848	2.63	1,358,003	2.89
Service operations expense	67,922	0.12	--	--
Oil and natural gas depreciation, depletion and amortization	1,358,519	2.35	894,035	1.91
Depreciation and amortization of other assets	104,240	0.18	50,966	0.11
Employee retirement expense	54,753	0.09	--	--
Total Operating Costs	3,912,373	6.77	2,892,130	6.17
INCOME FROM OPERATIONS	3,413,222	5.90	1,773,160	3.78
OTHER INCOME (EXPENSE):				
Interest and other income	25,463	0.05	10,452	0.02
Interest expense	(300,722)	(0.52)	(219,800)	(0.46)
Gain on sale of investment	117,396	0.20	--	--
Loss on repurchases or exchanges of senior notes		--	(70,419)	(0.15)
Total Other Income (Expense)	(157,863)	(0.27)	(279,767)	(0.59)
INCOME BEFORE INCOME TAXES	3,255,359	5.63	1,493,393	3.19
Income Tax Expense:				
Current	5,000	0.01	--	--
Deferred	1,247,036	2.16	545,091	1.17
Total Income Tax Expense	1,252,036	2.17	545,091	1.17
NET INCOME	2,003,323	3.46	948,302	2.02
Preferred stock dividends	(88,645)	(0.15)	(41,813)	(0.09)
Loss on exchange/conversion of preferred stock	(10,556)	(0.02)	(26,874)	(0.05)

NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	1,904,122	3.29	879,615	1.88

EARNINGS PER COMMON SHARE:

	2006	2005
Basic	$4.78	$2.73
Assuming dilution	$4.35	$2.51

WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)

Basic	398,487	322,034
Assuming dilution	458,603	366,683

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

	December 31, 2006	December 31, 2005
Cash	$ 2,519	$60,027
Other current assets	1,151,350	1,123,370
Total Current Assets	1,153,869	1,183,397
Property and equipment (net)	21,904,043	14,411,887
Other assets	1,359,255	523,178
Total Assets	$24,417,167	$16,118,462
Current liabilities	$1,889,809	$1,964,088
Long-term debt	7,375,548	5,489,742
Asset retirement obligation	192,772	156,593
Other long-term liabilities	390,108	528,738
Deferred tax liability	3,317,459	1,804,978
Total Liabilities	13,165,696	9,944,139
Stockholders' Equity	11,251,471	6,174,323
Total Liabilities & Stockholders' Equity	$24,417,167	$16,118,462
Common Shares Outstanding	457,434	370,190

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION
(in 000's)
(unaudited)

% of Total % of Total

	December 31, 2006	Book Capitalization	December 31, 2005	Book Capitalization
Long-term debt, net	$7,375,548	40%	$5,489,742	47%
Stockholders' equity	11,251,471	60%	6,174,323	53%
Total	$18,627,019	100%	$11,664,065	100%

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 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	$3,120,852	1,557,644(a)	$2.00
Acquisition of proved properties	1,175,616	668,178	$1.76
Subtotal	4,296,468	2,225,822	$1.93
Divestitures	(118)	(141)	
Geological and geophysical costs	153,993	--	
Adjusted subtotal	4,450,343	2,225,681	$2.00
Revisions - price	--	(212,374)	
Acquisition of unproved properties	2,855,848	--	
Leasehold acquisition costs	616,550	--	
Adjusted subtotal	7,922,741	2,013,307	$3.94
Tax basis step-up	179,731	--	
Asset retirement obligation	23,214	--	
Total	$8,125,686	2,013,307	$4.04

(a) Includes positive performance revisions of 729 bcfe and excludes downward revisions of 212 bcfe resulting from natural gas price declines between December 31, 2006 and 2005.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
TWELVE MONTHS ENDED DECEMBER 31, 2006
(unaudited)

	Mmcfe
Beginning balance, 01/01/06	7,520,690
Extensions and discoveries	828,594
Acquisitions	668,178
Revisions - performance	729,050
Revisions - price	(212,374)
Production	(578,383)
Divestitures	(141)
Ending balance, 12/31/06	8,955,614
Reserve replacement	2,013,307

Reserve replacement rate	348%

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

	THREE MONTHS ENDED December 31,		TWELVE MONTHS ENDED December 31,	
	2006	2005	2006	2005
Oil and Natural Gas Sales ($ in thousands):				
Oil sales	$122,092	$111,513	$526,687	$401,845
Oil derivatives - realized gains (losses)	10,820	(5,478)	(14,875)	(34,132)
Oil derivatives - unrealized gains (losses)	3,634	10,325	28,459	4,374
Total Oil Sales	136,546	116,360	540,271	372,087
Natural gas sales	816,888	1,225,616	3,343,056	3,231,286
Natural gas derivatives - realized gains (losses)	435,759	(269,596)	1,268,528	(367,551)
Natural gas derivatives - unrealized gains (losses)	39,271	167,934	467,039	36,763
Total Natural Gas Sales	1,291,918	1,123,954	5,078,623	2,900,498
Total Oil and Natural Gas Sales	$1,428,464	$1,240,314	$5,618,894	$3,272,585
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$55.07	$55.37	$60.86	$52.20
Natural gas ($ per mcf)	$5.89	$10.36	$6.35	$7.65
Natural gas equivalent ($ per mcfe)	$6.17	$10.25	$6.69	$7.75
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$59.95	$52.65	$59.14	$47.77
Natural gas ($ per mcf)	$9.03	$8.08	$8.76	$6.78

Natural gas equivalent ($ per mcfe)	$9.11	$8.14	$8.86	$6.90

Interest Expense ($ in thousands)				
Interest	$78,618	$66,121	$300,450	$226,330
Derivatives - realized (gains) losses	2,750	(2,306)	1,898	(4,945)
Derivatives - unrealized (gains) losses	(872)	362	(1,626)	(1,585)
Total Interest Expense	$80,496	$64,177	$300,722	$219,800

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

THREE MONTHS ENDED:	December 31, 2006	December 31, 2005
Beginning cash	$716	$127,102
Cash provided by operating activities	1,861,055	829,543
Cash (used in) investing activities	(2,274,494)	(3,266,334)
Cash provided by financing activities	415,242	2,369,716
Ending cash	$2,519	$60,027

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

TWELVE MONTHS ENDED:	December 31, 2006	December 31, 2005
Beginning cash	$60,027	$6,896
Cash provided by operating activities	4,843,474	2,406,888
Cash (used in) investing activities	(8,942,499)	(6,921,378)
Cash provided by financing activities	4,041,517	4,567,621
Ending cash	$2,519	$60,027

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

THREE MONTHS ENDED:	December 31, 2006	September 30, 2006	December 31, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$1,861,055	$937,275	$829,543

Adjustments:			
Changes in assets and liabilities	(765,578)	51,328	3,250
OPERATING CASH FLOW*	$1,095,477	$988,603	$832,793

*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:	December 31, 2006	September 30, 2006	December 31, 2005
NET INCOME	$471,362	$548,335	$452,525
Income tax expense	288,900	336,074	260,114
Interest expense	80,496	74,112	64,177
Depreciation and amortization of other assets	30,189	27,016	16,175
Oil and natural gas depreciation, depletion and amortization	381,680	343,723	272,551
EBITDA**	$1,252,627	$1,329,260	$1,065,542

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

THREE MONTHS ENDED:	December 31, 2006	September 30, 2006	December 31, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$1,861,055	$937,275	$829,543
Changes in assets and liabilities	(765,578)	51,328	3,250
Interest expense	80,496	74,112	64,177
Unrealized gains on oil and natural gas derivatives	42,905	238,518	178,259
Other non-cash items	33,749	28,027	(9,687)
EBITDA	$1,252,627	$1,329,260	$1,065,542

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

TWELVE MONTHS ENDED:	December 31, 2006	December 31, 2005	December 31, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$4,843,474	$2,406,888	$1,432,274
Adjustments:			
Changes in assets and liabilities	(798,365)	18,839	(29,752)
OPERATING CASH FLOW*	$4,045,109	$2,425,727	$1,402,522

*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.

TWELVE MONTHS ENDED:	December 31, 2006	December 31, 2005	December 31, 2004
NET INCOME	$2,003,323	$948,302	$515,155
Income tax expense	1,252,036	545,091	289,771
Interest expense	300,722	219,800	167,328
Depreciation and amortization of other assets	104,240	50,966	29,185
Oil and natural gas depreciation, depletion and amortization	1,358,519	894,035	582,137
EBITDA**	$5,018,840	$2,658,194	$1,583,576

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

TWELVE MONTHS ENDED:	December 31, 2006	December 31, 2005	December 31, 2004

CASH PROVIDED BY OPERATING ACTIVITIES	$4,843,474	$2,406,888	$1,432,274
Changes in assets and liabilities	(798,365)	18,839	(29,752)
Interest expense	300,722	219,800	167,328
Unrealized gains (losses) on oil and natural gas derivatives	495,498	41,137	40,887
Other non-cash items	177,511	(28,470)	(27,161)
EBITDA	$5,018,840	$2,658,194	$1,583,576

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

THREE MONTHS ENDED:	December 31, 2006	September 30, 2006	December 31, 2005
Net income available to common shareholders	$445,510	$522,582	$431,832
Adjustments:			
Loss on conversion/exchange of preferred stock	--	--	4,406
Unrealized (gains) losses on derivatives, net of tax	(27,142)	(149,457)	(112,965)
Loss on repurchases or exchanges of senior notes, net of tax	--	--	236
Adjusted net income available to common shareholders*	418,368	373,125	323,509
Preferred dividends	25,852	25,753	16,287
Total adjusted net income	$444,220	$398,878	$339,796
Weighted average fully diluted shares outstanding**	491,000	483,273	404,845
Adjusted earnings per share assuming dilution	$0.90	$0.83	$0.84

*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 is more comparable to earnings estimates provided by securities analysts.

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

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

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

THREE MONTHS ENDED:	December 31, 2006	September 30, 2006	December 31, 2005
EBITDA	$1,252,627	$1,329,260	$1,065,542
Adjustments, before tax:			
Unrealized (gains) losses on oil and natural gas derivatives	(42,905)	(238,518)	(178,259)
Loss on repurchases or exchanges of senior notes	--	--	372
Adjusted ebitda*	$1,209,722	$1,090,742	$887,655

*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.

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

TWELVE MONTHS ENDED:	December 31, 2006	December 31, 2005	December 31, 2004
Net income available to common shareholders	$1,904,122	$879,615	$438,971
Adjustments:			
Loss on conversion/exchange of preferred stock	10,556	26,874	36,678
Unrealized (gains) losses on derivatives, net of tax	(308,218)	(27,128)	(22,751)
Cumulative impact of new Texas margin tax	15,000	--	--
Reversal of severance tax accrual, net of tax	(7,192)	--	--
Gain on sale of investment, net of tax	(72,786)	--	--
Employee retirement expense, net of tax	33,947	--	--
Loss on repurchases or			

exchanges of senior notes,			
net of tax	--	44,716	15,716
Provision for legal			
settlement	--	--	2,880
Adjusted net income available			
to common shareholders*	1,575,429	924,077	471,494
Preferred dividends	88,645	41,813	39,506
Total adjusted net income	$1,664,074	$965,890	$511,000
Weighted average fully diluted			
shares outstanding**	460,693	375,294	327,058
Adjusted earnings per share			
assuming dilution	$3.61	$2.57	$1.56

*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 is more comparable to earnings estimates provided by securities analysts.

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

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

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

TWELVE MONTHS ENDED:	December 31, 2006	December 31, 2005	December 31, 2004
EBITDA	$5,018,840	$2,658,194	$1,583,576
Adjustments, before tax:			
Unrealized (gains) losses			
on oil and natural gas			
derivatives	(495,498)	(41,137)	(40,887)
Reversal of severance tax			
accrual	(11,600)	--	--
Gain on sale of investment	(117,396)	--	--
Employee retirement expense	54,753	--	--
Loss on repurchases or			
exchanges of senior notes	--	70,419	24,557
Provision for legal			
settlement	--	--	4,500
Adjusted ebitda*	$4,449,099	$2,687,476	$1,571,746

*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.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF PV-10
($ in 000's)
(unaudited)

	December 31, 2006	December 31, 2005
Standardized measure of discounted future net cash flows (SMOG)	$10,006,571	$15,967,911
Discounted future cash flows for income taxes	3,640,539	6,965,683
Discounted future net cash flows before income taxes (PV-10)	$13,647,110	$22,933,594

PV-10 is discounted (at 10% per year) future net cash flows before income taxes. The standardized measure of discounted future net cash flows includes the effects of estimated future income tax expenses and is calculated in accordance with SFAS 69. Management uses PV-10 as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While PV-10 is based on prices, costs and discount factors which are consistent from company to company, the standardized measure is dependent on the unique tax situation of each individual company.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF FEBRUARY 22, 2007

Quarter Ending March 31, 2007; Year Ending December 31, 2007;
and Year Ending December 31, 2008.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of February 22, 2007, we are using the following key assumptions in our projections for the first quarter of 2007, the full-year 2007 and the full-year 2008.

The primary changes from our December 11, 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; and
2) Production, certain costs and capital expenditure assumptions have been updated.

	Quarter Ending 3/31/2007	Year Ending 12/31/2007	Year Ending 12/31/2008

Estimated Production			
Oil - mbbls	2,100	8,500	8,500
Natural gas - bcf	138 - 140	614 - 624	696 - 706
Natural gas equivalent - bcfe	150.5 - 152.5	665 - 675	747 - 757
Daily natural gas equivalent midpoint - in mmcfe	1,683	1,836	2,055
NYMEX Prices (a) (for calculation of realized hedging effects only):			
Oil - $/bbl	$55.62	$56.09	$56.25
Natural gas - $/mcf	$6.76	$7.32	$7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	$9.82	$9.88	$8.00
Natural gas - $/mcf	$3.05	$1.77	$1.35
Estimated Differentials to NYMEX Prices:			
Oil - $/bbl	6 - 8%	6 - 8%	6 - 8%
Natural gas - $/mcf	8 - 12%	9 - 13%	9 - 13%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.85 - 0.95	$0.90 - 1.00	$0.90 - 1.00
Production taxes (generally 6.0% of O&G revenues) (b)	$0.41 - 0.46	$0.41 - 0.46	$0.41 - 0.46
General and administrative	$0.20 - 0.25	$0.20 - 0.25	$0.22 - 0.27
Stock-based compensation (non-cash)	$0.08 - 0.10	$0.08 - 0.10	$0.08 - 0.10
DD&A of oil and natural gas assets	$2.40 - 2.60	$2.40 - 2.60	$2.50 - 2.70
Depreciation of other assets	$0.22 - 0.24	$0.24 - 0.28	$0.28 - 0.32
Interest expense(c)	$0.55 - 0.60	$0.60 - 0.65	$0.60 - 0.65
Other Income per Mcfe:			
Oil and natural gas marketing income	$0.06 - 0.08	$0.06 - 0.08	$0.06 - 0.08
Service operations income	$0.08 - 0.12	$0.08 - 0.12	$0.08 - 0.12
Book Tax Rate (About Equals 95% deferred)	38%	38%	38%
Equivalent Shares Outstanding - in millions:			
Basic	452	453	458
Diluted	518	519	524
Capital Expenditures - in millions:			
Drilling, leasehold and seismic	$1,100 -1,200	$4,700 - 4,900	$4,700 -4,900

(a) Oil NYMEX prices have been updated for actual contract prices through January 2007 and natural gas NYMEX prices have been updated for actual contract prices through February 2007.

(b) Severance tax per mcfe is based on NYMEX prices of $55.62 per bbl of oil and $7.40 to $8.40 per mcf of natural gas during Q1 2007, $56.09 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2007 and $56.25 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2008.

(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 open natural gas swaps in place and also has the following gains from lifted natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Total Estimated Total Natural Gas Production	Total Gains from Lifted Swaps ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
2007:						
Q1	33.6	$9.33	139.0	24%	$281.1	$2.02
Q2	63.5	$7.99	147.5	43%	$113.7	$0.77
Q3	74.9	$8.19	159.0	47%	$103.8	$0.65
Q4	83.2	$8.96	173.5	48%	$116.3	$0.67
Total 2007(1)	255.2	$8.54	619.0	41%	$614.9	$0.99
Total 2008(1)	378.7	$9.32	701.0	54%	$105.0	$0.15

Total 2009(1)	35.6	$8.25	750.0	5%	$3.9	$0.01

(1) Certain hedging arrangements include swaps with knockout prices ranging from $5.25 to $6.50 covering 146 bcf in 2007, $5.75 to $6.50 covering 160 bcf in 2008 and $5.90 to $6.25 covering 36 bcf in 2009.

The company currently has the following open natural gas collars in place

	Open Swaps in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
2007:					
Q1	--	--	--	139.0	0%
Q2	21.8	$6.76	$8.20	147.5	15%
Q3	22.1	$6.76	$8.20	159.0	14%
Q4	19.6	$7.13	$8.88	173.5	11%
Total 2007(1)	63.5	$6.88	$8.41	619.0	10%
Total 2008(1)	21.3	$7.38	$9.20	701.0	3%

(1) Certain collar arrangements include knockout prices ranging from $5.00 to $6.00 covering 52 bcf in 2007 and $5.00 to $6.00 covering 11 bcf in 2008.

Note: Not shown above are written call options covering 64.4 bcf of production in 2007 at a weighted average price of $9.56 for a weighted average premium of $0.54, 93.0 bcf of production in 2008 at a weighed average price of $10.20 for a weighted average premium of $0.70 and 42.9 bcf of production in 2009 at a weighed average price of $11.41 for a weighted average premium of $0.50.

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*:
2007	176.6	0.43	36.5	0.35
2008	118.6	0.27	36.6	0.35
2009	86.6	0.29	18.2	0.31
Totals	381.8	$0.35	91.3	$0.34

* weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($357 million as of December 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 assumed CNR derivative instruments are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows.

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

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
2007:						
Q1	10.3	$4.82	$10.97	($6.15)	139.0	7%
Q2	10.5	$4.82	$8.48	($3.66)	147.5	7%
Q3	10.6	$4.82	$8.45	($3.63)	159.0	7%
Q4	10.6	$4.82	$8.87	($4.05)	173.5	6%
Total 2007(1)	42.0	$4.82	$9.18	($4.36)	619.0	7%
Total 2008(1)	38.4	$4.68	$8.02	($3.34)	701.0	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	750.0	2%

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

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

	Open Swaps in mbbls	Avg. NYMEX Strike Price	Assuming Oil Production in mbbls of:	Open Swap Positions as a % of Estimated Total Oil Production	Total Gains from Lifted Swaps ($ millions)	Total Lifted Gain per bbl of Estimated Total Oil Production
2007:						
Q1	1,173	$71.98	2,095	56%	$2.5	$1.19
Q2	1,274	$72.12	2,120	60%	$2.1	$0.99
Q3	1,288	$71.89	2,140	60%	$2.1	$0.99
Q4	1,288	$71.61	2,145	60%	$2.1	$0.98
Total						

2007(1)	5,023	$71.90	8,500	59%	$8.8	$1.04
Total 2008(1)	4,300	$71.63	8,500	51%	$4.8	$0.57
Total 2009	183	$66.10	8,500	2%	--	--

(1) Certain hedging arrangements include swaps with knockout prices ranging from $45.00 to $60.00 covering 1,460 mbbls in 2007 and $45.00 to $60.00 covering 1,098 mbbls in 2008.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF DECEMBER 11, 2006 (PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF FEBRUARY 22, 2007

Quarter Ending December 31, 2006; Year Ending December 31, 2006; Year Ending December 31, 2007; and Year Ending December 31, 2008.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of December 11, 2006, we are using the following key assumptions in our projections for the fourth quarter of 2006, the full-year 2006, the full-year 2007 and the full-year 2008.

The primary changes from our October 26, 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;
2) We have updated for our EUR 600 million Senior Note Offering; and
3) We have updated for our 30 million share Common Stock offering announced on December 7, 2006.

	Quarter Ending 12/31/2006	Year Ending 12/31/2006
Estimated Production		
Oil - mbbls	2,100	8,500
Natural gas - bcf	139 - 141	527 - 529
Natural gas equivalent - bcfe	151.5 - 153.5	578 - 580
Daily natural gas equivalent midpoint - in mmcfe	1,658	1,586
NYMEX Prices (a) (for calculation of realized hedging effects only):		
Oil - $/bbl	$58.26	$65.73
Natural gas - $/mcf	$6.56	$7.24
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Oil - $/bbl	$6.52	-$1.32
Natural gas - $/mcf	$3.17	$2.59
Estimated Differentials to NYMEX Prices:		
Oil - $/bbl	6 - 8%	7 - 9%
Natural gas - $/mcf	8 - 12%	10 - 15%
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.85 - 0.95	$0.85 - 0.90

Production taxes (generally 6.0% of O&G revenues) (b)	$0.36 - 0.40	$0.35 - 0.40
General and administrative	$0.17 - 0.22	$0.15 - 0.20
Stock-based compensation (non-cash)	$0.10 - 0.11	$0.06 - 0.08
DD&A of oil and natural gas assets	$2.35 - 2.40	$2.30 - 2.35
Depreciation of other assets	$0.19 - 0.23	$0.18 - 0.22
Interest expense(c)	$0.58 - 0.62	$0.54 - 0.58
Other Income per Mcfe:		
Oil and natural gas marketing income	$0.02 - 0.04	$0.06 - 0.08
Service operations income	$0.08 - 0.10	$0.08 - 0.10
Book Tax Rate (About Equals 95% deferred)	38%	38%
Equivalent Shares Outstanding - in millions:		
Basic	426	398
Diluted	492	460
Capital Expenditures - in millions:		
Drilling, leasehold and seismic	$1,100 -1,300	$4,700 - 4,900

	Year Ending 12/31/2007	Year Ending 12/31/2008
Estimated Production		
Oil - mbbls	8,500	8,500
Natural gas - bcf	614 - 624	696 - 706
Natural gas equivalent - bcfe	665 - 675	747 - 757
Daily natural gas equivalent midpoint - in mmcfe	1,836	2,055
NYMEX Prices (a) (for calculation of realized hedging effects only):		
Oil - $/bbl	$56.25	$56.25
Natural gas - $/mcf	$7.50	$7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Oil - $/bbl	$10.43	$8.65
Natural gas - $/mcf	$1.62	$1.02
Estimated Differentials to NYMEX Prices:		
Oil - $/bbl	6 - 8%	6 - 8%
Natural gas - $/mcf	9 - 13%	9 - 13%
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.90 - 1.00	$0.90 - 1.00
Production taxes (generally 6.0% of O&G revenues) (b)	$0.41 - 0.46	$0.41 - 0.46
General and administrative	$0.20 - 0.25	$0.22 - 0.27
Stock-based compensation (non-cash)	$0.08 - 0.10	$0.08 - 0.10
DD&A of oil and natural gas assets	$2.40 - 2.50	$2.40 - 2.50
Depreciation of other assets	$0.24 - 0.28	$0.28 - 0.32
Interest expense(c)	$0.60 - 0.65	$0.60 - 0.65
Other Income per Mcfe:		
Oil and natural gas marketing income	$0.06 - 0.08	$0.06 - 0.08
Service operations income	$0.10 - 0.12	$0.10 - 0.12
Book Tax Rate (About Equals 95% deferred)	38%	38%
Equivalent Shares Outstanding - in millions:		
Basic	453	458
Diluted	519	524
Capital Expenditures - in millions:		
Drilling, leasehold and seismic	$4,700 - 4,900	$4,700 -4,900

(a) Oil NYMEX prices have been updated for actual contract prices through November 2006 and natural gas NYMEX prices have been updated for actual contract prices through December 2006.

(b) Severance tax per mcfe is based on NYMEX prices of $58.26 per bbl of oil and $6.40 to $7.20 per mcf of natural gas during Q4 2006, $65.73 per bbl of oil and $6.20 to $7.20 per mcf of natural gas during calendar 2006, $56.25 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2007 and 2008.

(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 open natural gas swaps in place and also has the following gains from lifted natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production in Bcf's of:	Total Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Lifted Gains from Lifted Swaps ($ millions)	Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q4 2006(1)	58.3	$8.83	140.0	42%	$237	$1.69
2007:						
Q1	42.5	$10.16	143.2	30%	$268	$1.87
Q2	21.7	$9.52	150.6	14%	$96	$0.64

Q3	26.2	$9.63	159.2	16%	$88	$0.55
Q4	26.2	$10.44	166.0	16%	$113	$0.68
Total 2007(1)	116.6	$9.98	619.0	19%	$565	$0.91

Total 2008(1)	263.6	$9.57	701.0	38%	$85	$0.12

Total 2009			750.0		$4	$0.01

(1) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 8.6 bcf in 2006, $5.30 to $6.50 covering 70.6 bcf in 2007 and $5.75 to $6.50 covering 76.9 bcf in 2008, respectively.

Note: Not shown above are call options covering 1.8 bcf of production in 2006 at a weighted average price of $12.50, 7.3 bcf of production in 2007 at a weighted average price of $12.50 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*:
Q4 2006	36.8	$0.37	-	$-
2007	141.7	0.34	36.5	0.35
2008	118.6	0.27	36.6	0.35
2009	86.6	0.29	18.2	0.31
Totals	383.7	$0.31	91.3	$0.34

* weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($415 million as of September 30, 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:

	Avg.		Open Swap

	Open Swaps in Bcf's	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:	Positions as a % of Estimated Total Natural Gas Production
Q4 2006	10.6	$4.86	$10.38	($5.52)	140.0	8%
2007:						
Q1	10.3	$4.82	$10.97	($6.15)	143.2	7%
Q2	10.5	$4.82	$8.48	($3.66)	150.6	7%
Q3	10.6	$4.82	$8.45	($3.63)	159.2	7%
Q4	10.6	$4.82	$8.87	($4.05)	166.0	6%
Total 2007	42.0	$4.82	$9.18	($4.36)	619.0	7%
Total 2008	38.4	$4.67	$8.01	($3.34)	701.0	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	750.0	2%

Note: Not shown above are collars covering 3.7 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00, 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:	Open Swap Positions as a % of Estimated Total Oil Production	Total Gains from Lifted Swaps ($ millions)	Total Lifted Gain per bbl of Estimated Total Oil Production
Q4 2006	1,530	$65.85	2,100	73%	$1.7	$0.81
2007:						
Q1	1,297	$71.43	2,095	62%	$2.2	$1.05
Q2	1,456	$72.16	2,120	69%	-	-
Q3	1,472	$71.92	2,140	69%	-	-
Q4	1,472	$71.62	2,145	69%	-	-
Total 2007(1)	5,697	$71.79	8,500	67%	$2.2	$0.26
Total 2008(1)	5,032	$71.45	8,500	59%	-	-
Total 2009	183	$66.10	8,500	2%	-	-

(1) Certain hedging arrangements include swaps with knockout prices ranging from $40.00 to $60.00 covering 184 mbbls in 2006, $45.00 to $60.00 covering 1,460 mbbls in 2007 and $45.00 to $60.00 covering 1,098 mbbls in 2008, respectively.

CONTACT: Chesapeake Energy Corporation

Jeffrey L. Mobley, CFA, 405-767-4763
Senior Vice President - Investor Relations and Research
Jmobley@Chkenergy.Com
or
Marc Rowland, 405-879-9232
Executive Vice President and Chief Financial Officer
Mrowland@Chkenergy.Com

SOURCE: Chesapeake Energy Corporation
