News Release

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CHESAPEAKE ENERGY CORPORATION REPORTS STRONG FINANCIAL AND OPERATIONAL RESULTS FOR THE 2007 SECOND QUARTER

Net Income Available to Common Shareholders Reaches $492 Million on Revenue of $2.1 Billion; Adjusted Net Income Available to Common Shareholders Reaches $342 Million

Production of 1.868 Bcfe per Day Increases 9% Sequentially and 19% Year Over Year; Chesapeake Now the Largest Independent Producer of U.S. Natural Gas

Proved Reserves Reach Record Level of 10.0 Tcfe; Company Delivers First Half 2007 Reserve Replacement Rate of 416% from 1.023 Tcfe of Additions

Company Announces Plans to Sell a Portion of its Appalachian Production and Proved Reserves; Proceeds of at Least $600 Million Expected

OKLAHOMA CITY, OKLAHOMA, AUGUST 2, 2007 – Chesapeake Energy Corporation (NYSE:CHK) today reported strong financial and operating results for the second quarter of 2007. For the quarter, Chesapeake generated net income available to common shareholders of $492 million ($1.01 per fully diluted common share), operating cash flow of $1.076 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.401 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $2.105 billion and production of 170 billion cubic feet of natural gas equivalent (bcfe).

The company's 2007 second 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 2007 second quarter reported results are described as follows:

- an unrealized after-tax mark-to-market gain of $98.5 million resulting from the company's oil and natural gas and interest rate hedging programs;
- an after-tax gain of $51.3 million resulting from the sale of the company's investment in Eagle Energy Partners I, L.P.

Excluding the above-mentioned items, Chesapeake generated adjusted net income to common shareholders in the 2007 second quarter of $342 million ($0.71 per fully diluted common share) and adjusted ebitda of $1.167 billion. The excluded 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 21 - 24 of this release.

Key Operational and Financial Statistics Summarized Below for the 2007 Second Quarter, 2007 First Quarter and 2006 Second Quarter

The table below summarizes Chesapeake's key results during the 2007 second quarter and compares them to the 2007 first quarter and the 2006 second quarter.

	Three Months Ended:		
	6/30/07	3/31/07	6/30/06
Average daily production (in mmcfe)	1,868	1,707	1,568
Natural gas as % of total production	92	92	91
Natural gas production (in bcf)	156.1	140.8	129.8
Average realized natural gas price ($/mcf) (a)	7.97	9.26	8.04
Oil production (in mbbls)	2,324	2,143	2,143
Average realized oil price ($/bbl) (a)	65.37	61.13	58.80
Natural gas equivalent production (in bcfe)	170.0	153.7	142.7
Natural gas equivalent realized price ($/mcfe) (a)	8.21	9.33	8.20
Oil and natural gas marketing income ($/mcfe)	.11	.10	.08
Service operations income ($/mcfe)	.07	.08	.10
Production expenses ($/mcfe)	(.90)	(.93)	(.85)
Production taxes ($/mcfe)	(.31)	(.27)	(.24)
General and administrative costs ($/mcfe) (b)	(.25)	(.27)	(.19)
Stock-based compensation ($/mcfe)	(.07)	(.07)	(.05)
DD&A of oil and natural gas properties ($/mcfe)	(2.60)	(2.56)	(2.30)
D&A of other assets ($/mcfe)	(.23)	(.23)	(.16)
Interest expense ($/mcfe) (a)	(.54)	(.50)	(.51)
Operating cash flow ($ in millions) (c)	1,076	1,124	914
Operating cash flow ($/mcfe)	6.33	7.31	6.41
Adjusted ebitda ($ in millions) (d)	1,167	1,234	1,001
Adjusted ebitda ($/mcfe)	6.86	8.03	7.02
Net income to common shareholders ($ in millions)	492	232	332
Earnings per share – assuming dilution ($)	1.01	0.50	0.82
Adjusted net income to common shareholders ($ in millions) (e)	342	425	340
Adjusted earnings per share – assuming dilution ($)	0.71	0.87	0.82

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

Oil and Natural Gas Production Sets Record for 24th Consecutive Quarter; 2007 Second Quarter Average Daily Production Increases 9% and 19% Over Production in the 2007 First Quarter and the 2006 Second Quarter; Company Now the Largest Independent Producer of U.S. Natural Gas

Daily production for the 2007 second quarter averaged 1.868 bcfe, an increase of 300 million cubic feet of natural gas equivalent (mmcfe), or 19%, over the 1.568 bcfe of daily production in the 2006 second quarter and an increase of 161 mmcfe, or 9%, over the 1.707 bcfe produced per day in the 2007 first quarter.

Chesapeake's 2007 second quarter production of 170.0 bcfe was comprised of 156.1 billion cubic feet of natural gas (bcf) (92% on a natural gas equivalent basis) and 2.324 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis). Chesapeake's average daily production for the quarter of 1.868 bcfe consisted of 1.715 bcf of natural gas and 25,538 barrels (bbls) of oil. Based on 2007 second quarter reported production from continuing operations reported by other public U.S. natural gas producers, Chesapeake believes it has recently become the largest independent and third-largest overall producer of U.S. natural gas.

The 2007 second quarter was Chesapeake's 24th consecutive quarter of sequential U.S. production growth. Over these 24 quarters, Chesapeake's U.S. production has increased 372%, for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 30%.

As a result of better than expected performance from the company's accelerated drilling program and the addition of approximately 40 mmcfe per day of production from its July 2007 transaction with Anadarko Petroleum Corporation (NYSE:APC) in Deep Haley, Chesapeake is raising its previous forecasts for total production growth for 2007 to 18-22% from 14-18% and for 2008 to 14-18% from 10-14%. The company's rate of production has recently exceeded 1.975 bcfe per day and based on projected drilling levels and anticipated results, Chesapeake expects its 2007 production exit rate to be at least 2.05-2.10 bcfe per day.

Oil and Natural Gas Proved Reserves Reach Record Level of 10 Tcfe; Drilling and Acquisition Costs Average $2.11 per Mcfe as Company Adds 1.023 Tcfe for a Reserve Replacement Rate of 416%

Chesapeake began 2007 with estimated proved reserves of 8.956 trillion cubic feet of natural gas equivalent (tcfe) and ended the second quarter with 9.979 tcfe, an increase of 1.023 tcfe, or 11%. During the 2007 first half, Chesapeake replaced its 324 bcfe of production with an estimated 1.347 tcfe of new proved reserves for a reserve replacement rate of 416%. Reserve replacement through the drillbit was 1.145 tcfe, or 354% of production (including 510 bcfe of positive performance revisions and 95 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and June 30, 2007) and 85% of the total increase. Reserve replacement through the acquisition of proved reserves completed during the 2007 first half was 202 bcfe, or 62% of production and 15% of the total increase.

On a per thousand cubic feet of natural gas equivalent (mcfe) basis, the company's total drilling and acquisition costs for the first half of 2007 were $2.11 per mcfe (excluding costs of $134 million for seismic, $1.075 billion for unproved properties, leasehold acquired and related capitalized interest, and $110 million relating to tax basis step-up and asset retirement obligations, as well as positive revisions of proved reserves from higher oil and natural gas prices). Excluding these same items, Chesapeake's exploration and development costs through the drillbit were $2.14 per mcfe during the 2007 first half while reserve replacement costs through acquisitions of proved reserves were $1.97 per mcfe. Total costs incurred in oil and natural gas acquisition, exploration and development activities during the 2007 first half, including seismic, leasehold, unproved properties, capitalized interest and internal costs, non-cash tax basis step-up from corporate acquisitions and asset retirement obligations, were $3.962 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 the 2007 first half, Chesapeake continued the industry's most active drilling program and drilled 977 gross (835 net) operated wells and participated in another 826 gross (115 net) wells operated by other companies. The company's drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during the 2007 first half, Chesapeake invested $1.932 billion in operated wells (using an average of 131 operated rigs), $314 million in non-operated wells (using an average of 102 non-operated rigs), $410 million to acquire new leasehold (exclusive of $665 million in unproved leasehold obtained through corporate and asset acquisitions, as well as other leasehold fees and related capitalized interest) and $134 million to acquire seismic data.

As of June 30, 2007, Chesapeake's estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10) were $18.8 billion using field differential adjusted prices of $65.41 per bbl (based on a NYMEX quarter-end price of $70.33 per bbl) and $6.25 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $6.80 per mcf).

By comparison, the December 31, 2006 PV-10 of the company's proved reserves was $13.6 billion using field differential adjusted prices of $56.25 per bbl (based on a NYMEX year-end price of $61.15 per bbl) and $5.41 per mcf (based on a NYMEX year-end price of $5.64 per mcf). Including the effect of income taxes, the standardized measure of discounted future net cash flows from proved reserves at year-end 2006 was $10.0 billion. By further comparison, the June 30, 2006 PV-10 of the company's proved reserves was $15.0 billion using field differential adjusted prices of $69.10 per bbl (based on a NYMEX quarter-end price of $73.86 per bbl) and $5.72 per mcf (based on a NYMEX quarter-end price of $6.09 per mcf).

Chesapeake's current PV-10 changes by approximately $365 million for every $0.10 per mcf change in natural gas prices and approximately $53 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 interim period-end values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects.

In addition to the PV-10 value of its proved reserves, the net book value of the company's other assets (including drilling rigs, gathering systems, compressors, land and buildings, investments, long-term derivative instruments and other non-current assets) was $2.8 billion as of June 30, 2007, $2.8 billion as of December 31, 2006 and $1.8 billion as of June 30, 2006.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2007 second quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $65.37 per bbl of oil and $7.97 per mcf of natural gas, for a realized natural gas equivalent price of $8.21 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the second quarter were a negative $4.93 per bbl and a negative $0.77 per mcf. Realized gains from oil and natural gas hedging activities during the quarter generated a $5.27 gain per bbl and a $1.19 gain per mcf, for a 2007 second quarter realized hedging gain of $198 million, or $1.16 per mcfe.

The following tables compare Chesapeake's open hedge position through swaps and collars as well as gains from lifted hedges as of August 2, 2007 to those previously announced as of May 3, 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 August 2, 2007

	Natural Gas		Oil	
Quarter or Year	**% Hedged**	**$ NYMEX**	**% Hedged**	**$ NYMEX**
2007 Q3	57%	8.29	74%	71.61
2007 Q4	61%	9.00	72%	71.57
2007 Q3-Q4 Total	59%	8.66	73%	71.59
2008 Total	64%	9.22	74%	72.77
2009 Total	16%	9.11	32%	77.58

Open Natural Gas Collar Positions as of August 2, 2007

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2007 Q3	13%	6.76	8.20
2007 Q4	11%	7.13	8.88
2007 Q3-Q4 Total	12%	6.94	8.52
2008 Total	4%	7.41	9.40
2009 Total	2%	7.50	10.72

Gains From Lifted Natural Gas Hedges as of August 2, 2007

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2007 Q3	111	168.5	0.66
2007 Q4	117	173.5	0.67
2007 Q3-Q4 Total	228	342.0	0.67
2008 Total	105	745.5	0.14
2009 Total	4	816.0	0.01

Additionally, the company has lifted a portion of its oil hedges securing gains of $4.2 million and $4.8 million for the last half of 2007 and for the full year 2008, respectively.

Open Swap Positions as of May 3, 2007

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2007 Q2	53%	8.11	77%	71.22
2007 Q3	54%	8.30	77%	71.61
2007 Q4	55%	8.98	77%	71.57
2007 Q2-Q4 Total	54%	8.49	77%	71.47
2008 Total	64%	9.20	72%	72.61
2009 Total	13%	8.87	19%	75.41

Open Natural Gas Collar Positions as of May 3, 2007

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2007 Q2	15%	6.76	8.20
2007 Q3	14%	6.76	8.20
2007 Q4	11%	7.13	8.88
2007 Q2-Q4 Total	13%	6.88	8.41
2008 Total	4%	7.41	9.40
2009 Total	2%	7.50	10.72

Gains From Lifted Natural Gas Hedges as of May 3, 2007

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2007 Q2	112	147.5	0.76
2007 Q3	105	158.0	0.67
2007 Q4	117	172.5	0.68
2007 Q2-Q4 Total	334	478	0.70
2008 Total	105	701	0.15
2009 Total	4	750	0.01

Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $5.25 to $6.50 covering 116 bcf in 2007, $5.75 to $6.50 covering 222 bcf in 2008 and $5.90 to $6.50 covering 116 bcf in 2009. Certain open natural gas collar positions include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 33 bcf in 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $6.00 covering 18 bcf in 2009. Also, certain open oil swap positions include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 1 mmbbls in 2007 and 3 mmbbls in 2008, and from $52.50 to $60.00 covering 3 mmbbls in 2009.

The company's updated forecasts for 2007 and 2008 are attached to this release in an Outlook dated August 2, 2007 labeled as Schedule "A", which begins on page 25. This Outlook has been changed from the Outlook dated May 3, 2007 (attached as Schedule "B", which begins on page 29) to reflect various updated information.

Chesapeake's Leasehold and 3-D Seismic Inventories Now Total 12.2 Million Net Acres and 17.7 Million Acres; Risked Unproved Reserves in the Company's Inventory Now Reach 20.8 Tcfe, Bringing Total Reserve Base to 30.9 Tcfe

Since 2000, Chesapeake has invested $7.8 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (12.2 million net acres) and 3-D seismic (17.7 million acres) in the U.S. On this leasehold, the company has approximately 28,500 net drilling locations, representing an approximate 10-year inventory of drilling projects, on which it believes it can develop an estimated 3.8 tcfe of proved undeveloped reserves and approximately 20.8 tcfe of risked unproved reserves (82 tcfe of unrisked unproved reserves). Pro forma for its July 2007 transaction with Anadarko in Deep Haley, Chesapeake's 10.1 tcfe of estimated proved reserves and its 20.8 tcfe of estimated risked unproved reserves total approximately 30.9 tcfe.

To aggressively develop these assets, Chesapeake has continued to significantly strengthen its technical capabilities by increasing its land, geoscience and engineering staff to over 1,200 employees. Today, the company has approximately 5,800 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 13.7 million acres of 3-D seismic data. Chesapeake is producing approximately 985 mmcfe net per day in conventional gas resource plays and owns 3.4 million net acres on which it has an estimated 3.0 tcfe of proved developed reserves, 1.0 tcfe of proved undeveloped reserves and approximately 3.1 tcfe of estimated risked unproved reserves. In these plays the company is currently using 36 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 200 mmcfe net per day. The company is currently using nine operated rigs to further develop its 335,000 net acres of leasehold.

Chesapeake's proved developed reserves in southern Oklahoma are an estimated 552 bcfe, its proved undeveloped reserves are an estimated 239 bcfe and its estimated risked unproved reserves are approximately 600 bcfe after applying a 75% risk factor and assuming an additional 500 net wells are drilled in the years ahead. The company's targeted results for vertical 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 135 mmcfe net per day. The company is currently using five operated rigs to further develop its 140,000 net acres of leasehold. Chesapeake's proved developed reserves in South Texas are an estimated 311 bcfe, its proved undeveloped reserves are an estimated 142 bcfe and its estimated risked unproved reserves are approximately 300 bcfe after applying a 75% risk factor and assuming an additional 340 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 120 mmcfe net per day. The company is currently using three operated rigs to further develop its 145,000 net acres of Mountain Front leasehold. Chesapeake's proved developed reserves in the Mountain Front area are an estimated 186 bcfe, its proved undeveloped reserves are an estimated 59 bcfe and its estimated risked unproved reserves are approximately 225 bcfe after applying a 70% risk factor and assuming an additional 90 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 plays, the company is producing approximately 830 mmcfe net per day. Pro forma for its transaction with Anadarko in Deep Haley, Chesapeake owns 3.2 million net acres in unconventional gas resource plays on which it has an estimated 2.2 tcfe of proved developed reserves, 2.3 tcfe of proved undeveloped reserves and approximately 12.8 tcfe of estimated risked unproved reserves and is currently using 95 operated drilling rigs to further develop its inventory of approximately 14,700 net drillsites. Six 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 third largest producer of natural gas, the most active driller and the largest leasehold owner in the Core and Tier 1 sweet spot of Tarrant, Johnson and western Dallas counties. Chesapeake is producing approximately 230 mmcfe net per day from the Fort Worth Barnett Shale. The company is currently using 35 operated rigs to further develop its 230,000 net acres of leasehold, of which 180,000 net acres are located in the prime Core and Tier 1 area. In the second half of 2007, Chesapeake expects to use 35-38 operated rigs in the play and to be completing, on average, one new Barnett Shale well approximately every 16 hours. Chesapeake's proved developed reserves in the Fort Worth Barnett Shale are an estimated 712 bcfe, its proved undeveloped reserves are an estimated 795 bcfe and its estimated risked unproved reserves are approximately 3.9 tcfe after applying a 15% risk factor in the Core and Tier 1 area and a 30% risk factor in other areas and assuming an additional 2,700 net wells are drilled in the years ahead. The company's targeted results for Core and 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.

- *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) and is producing approximately 35 mmcfe net per day. Chesapeake's net production levels have increased approximately five-fold since the beginning of the year as a result of the company's accelerated drilling program and better than expected well results. Since the beginning of the year, Chesapeake has increased its drilling activity levels more than three-fold to 12 operated rigs to further develop its 390,000 net acres of leasehold in the core area of the play. Chesapeake's proved developed reserves in the Fayetteville Shale are an estimated 69 bcfe, its proved undeveloped reserves are an estimated 76 bcfe and its estimated risked unproved reserves are approximately 3.8 tcfe after applying a 40% risk factor to its core area acreage and assuming an additional 2,900 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 using approximately 3,000' horizontal laterals. The company is currently risking its 690,000 net acres of non-core area leasehold at 100%.

- *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. Chesapeake is producing approximately 170 mmcfe net per day in the Sahara area. The company is currently using 14 operated rigs to further develop its 760,000 net acres of leasehold. Chesapeake's proved developed reserves in Sahara are an estimated 528 bcfe, its proved undeveloped reserves are an estimated 468 bcfe and its estimated risked unproved reserves are approximately 2.8 tcfe after applying a 25% risk factor and assuming an additional 6,700 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 70 acre spacing.

- *Deep Haley (primarily Strawn, Atoka, Morrow formations in West Texas):* In this West Texas Delaware Basin area, Chesapeake is the second largest leasehold owner and the most active driller. Following the company's transaction with Anadarko, Chesapeake's production from Deep Haley has increased to approximately 105 mmcfe net per day. The company will explore more than 1.0 million gross acres jointly with Anadarko. Chesapeake is currently using eight operated rigs to further develop its 600,000 net acres of leasehold. Pro forma for the company's transaction with Anadarko, Chesapeake's proved developed reserves in Deep Haley are an estimated 134 bcfe, its proved undeveloped reserves are an estimated 137 bcfe and its estimated risked unproved reserves are approximately 1.4 tcfe after applying a 80% risk factor and assuming an additional 350 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.

- *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 135 mmcfe net per day in the Ark-La-Tex area. The company is currently using 11 operated rigs to further develop its 200,000 net acres of leasehold. Chesapeake's unconventional proved developed reserves in the Ark-La-Tex region are an estimated 393 bcfe, its proved undeveloped reserves are an estimated 282 bcfe and its estimated unconventional risked unproved reserves are approximately 260 bcfe after applying a 70% risk factor and assuming an additional 750 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 various Wash plays of the Anadarko Basin. Chesapeake is producing approximately 140 mmcfe net per day from these plays. The company is currently using 14 operated rigs to further develop its 200,000 net acres of leasehold. Chesapeake's proved developed reserves in the Wash plays are an estimated 373 bcfe, its proved undeveloped reserves in the Wash plays are an estimated 511 bcfe and its estimated risked unproved reserves are approximately 600 bcfe after applying a 50% risk factor and assuming an additional 975 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 plays, commercial production has only recently been established but the company believes future reserve potential could be substantial. Chesapeake is producing approximately 25 mmcfe net per day in these plays and owns 1.8 million net acres on which it has an estimated 66 bcfe of proved developed reserves, 51 bcfe of proved undeveloped reserves and approximately 2.4 tcfe of estimated risked unproved reserves. In these plays, the company is currently using 11 operated drilling rigs to further develop its inventory of approximately 1,200 net drillsites. Three of Chesapeake's most important emerging unconventional gas resource plays are described below:

- *Delaware Basin Shales (primarily Barnett and Woodford formations in West Texas):* Chesapeake continues to evaluate a variety of drilling and completion techniques to test the commercial potential of its Delaware Basin Barnett and Woodford Shale play in far West Texas where Chesapeake is the largest leasehold owner. The company is producing approximately two mmcfe net per day from the Delaware Basin Barnett and Woodford Shales. The company is currently using two operated rigs and plans to increase its operated rig count to five rigs by year-end 2007 to further develop its 800,000 net acres of leasehold. Chesapeake's proved developed reserves in the Delaware Basin shales are an estimated 9 bcfe and it has not yet booked any proved undeveloped reserves. The company estimates its risked unproved reserves are 1.1 tcfe after applying a 90% risk factor and assuming an additional 500 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 15 mmcfe net per day from the Woodford Shale. The company is currently using six operated rigs to further develop its 100,000 net acres of leasehold. Chesapeake's proved developed reserves in the Woodford Shale are an estimated 32 bcfe, its proved undeveloped reserves in the play are an estimated 41 bcfe and its estimated risked unproved reserves are approximately 450 bcfe after applying a 50% risk factor and assuming an additional 275 net wells are drilled in the years ahead. The company's targeted results for horizontal Woodford Shale wells are $4.3 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 five mmcfe net per day in the Deep Bossier play. The company is currently using three operated rig and plans to increase its operated rig count to six rigs by year-end 2007 to further develop its 360,000 net acres of leasehold.

Chesapeake's proved developed reserves in the Deep Bossier are an estimated four bcfe, its proved undeveloped reserves are an estimated three bcfe and its estimated risked unproved reserves are approximately 400 bcfe after applying a 90% risk factor and assuming an additional 100 net wells are drilled in the years ahead. The company's targeted results for vertical Deep Bossier wells are $10.0 million to develop 5.0 bcfe on approximately 320 acre spacing.

Appalachian Basin Gas Resource Plays - Chesapeake's Appalachian 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 3.7 million net acres and is producing approximately 135 mmcfe net per day. The company is currently using 11 operated rigs in the region and plans to increase its operated rig count to 13 rigs by year-end 2007 to further develop its extensive leasehold position. In Appalachia, Chesapeake has an estimated 989 bcfe of proved developed reserves, an estimated 534 bcfe of proved undeveloped reserves and its estimated risked unproved reserves are approximately 2.5 tcfe after applying a 35% risk factor and assuming an additional 9,100 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.

Company Announces Plans to Sell a Portion of its Appalachian Production and Proved Reserves; Proceeds of at Least $600 Million Expected

As part of a value capture and asset monetization program designed to fund a portion of the company's accelerated drilling program and in recognition of the extremely attractive valuations available in the financial and master limited partnership markets for low-risk, long-reserve life, low-decline rate producing properties, Chesapeake has recently begun a process to divest a portion of its Appalachian producing properties in West Virginia and eastern Kentucky. The company intends to sell approximately 30 mmcfe net per day, or approximately 1.5% of the company's total current production, from an approximate 35% non-operated working interest in approximately 4,300 wells. The working interest to be sold will convey internally estimated proved reserves of approximately 235 bcfe, or approximately 2.3% of the company's current proved reserves. The company intends to retain drilling rights on the properties below currently producing intervals and outside of existing producing wellbores. Chesapeake expects to receive proceeds of at least $600 million from the Appalachian asset sale, which is anticipated to close by the end of 2007.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented "We are pleased to report outstanding financial and operational results for the 2007 second quarter. We are particularly proud of our success through the drillbit that has allowed the company to exceed its mid-year production and reserve growth expectations and become the nation's largest independent producer of natural gas and third largest overall. Our sequential quarter and year-over-year production growth levels of 161 mmcfe and 300 mmcfe per day are at the top of the U.S. exploration and production industry. Notably, these increases equal or exceed the total production of many small-cap high-growth companies that trade at significant valuation premiums and have enterprise values ranging from $5 to 10 billion.

The benefits of Chesapeake's strategic shift from resource capture to resource conversion are beginning to accelerate and we look forward to generating further strong growth in the second half of 2007 and in 2008. Through the industry's most active drilling program, we plan to increase our average daily production rate 18-22% in 2007 and 14-18% in 2008 and we expect to exceed 10.5 tcfe of proved reserves by year-end 2007 and approach 12 tcfe by year-end 2008.

The Fort Worth Barnett Shale play has been the largest contributor to the company's recent success and we are excited about the substantial competitive advantages we have created in the "sweet spot" of Tarrant, Johnson and western Dallas counties. In these areas, our leasehold position, surface drilling locations, land services agreements and gathering and water handling infrastructure are benefiting from rapidly developing economies of scale. We are also pleased to have recently expanded our position in the increasingly significant Deep Haley play in West Texas where the combined expertise of Chesapeake and Anadarko, two of the best deep gas explorers in the industry, should help further develop the play.

Also in the 2007 second quarter, the company delivered attractive profit margins that were enhanced by the company's well-executed hedging strategy and we look forward to delivering strong risk-adjusted returns for many quarters to come. Our focused business strategy, value-added growth, tremendous inventory of undrilled locations and valuable hedge positions continue to clearly differentiate Chesapeake in the industry."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, August 3, 2007 at 9:00 a.m. EDT. The telephone number to access the conference call is **913-981-5584** and the confirmation code is **4231813**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from noon EDT, August 3, 2007 through midnight EDT on August 17, 2007. The number to access the conference call replay is **719-457-0820** and the passcode for the replay is **4231813**. 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 in "Risks Related to our Business" under "Risk Factors" in the prospectus supplement we filed with the Securities and Exchange Commission on May 10, 2007 and in Item 1A of our 2006 annual report on Form 10-K filed on March 1, 2007. These risk factors 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 amount and 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; drilling and operating risks, including potential environmental liabilities; production interruptions that could adversely affect our cash flow; and pending or future litigation.

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

The SEC has generally permitted 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 largest independent and third-largest overall 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, Fayetteville Shale, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast, Ark-La-Tex and Appalachian Basin 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:	June 30, 2007 $	June 30, 2007 $/mcfe	June 30, 2006 $	June 30, 2006 $/mcfe
REVENUES:				
Oil and natural gas sales	1,547,524	9.09	1,186,383	8.32
Oil and natural gas marketing sales	523,069	3.08	367,610	2.57
Service operations revenue	33,909	0.20	30,023	0.21
Total Revenues	2,104,502	12.37	1,584,016	11.10
OPERATING COSTS:				
Production expenses	153,004	0.90	120,697	0.85
Production taxes	53,199	0.31	33,923	0.24
General and administrative expenses	54,310	0.32	33,555	0.24
Oil and natural gas marketing expenses	504,386	2.97	355,688	2.48
Service operations expense	22,405	0.13	15,667	0.11
Oil and natural gas depreciation, depletion and amortization	442,063	2.60	328,159	2.30
Depreciation and amortization of other assets	39,844	0.23	23,163	0.16
Total Operating Costs	1,269,211	7.46	910,852	6.38
INCOME FROM OPERATIONS	835,291	4.91	673,164	4.72
OTHER INCOME (EXPENSE):				
Interest and other income	1,451	0.01	4,974	0.03
Interest expense	(83,732)	(0.49)	(73,456)	(0.51)
Gain on sale of investment	82,705	0.49	—	—
Total Other Income (Expense)	424	0.01	(68,482)	(0.48)
INCOME BEFORE INCOME TAXES	835,715	4.92	604,682	4.24
Income Tax Expense:				
Current	—	—	—	—
Deferred	317,570	1.87	244,779	1.72
Total Income Tax Expense	317,570	1.87	244,779	1.72
NET INCOME	518,145	3.05	359,903	2.52
Preferred stock dividends	(25,836)	(0.15)	(18,228)	(0.12)
Loss on exchange/conversion of preferred stock	—	—	(9,547)	(0.07)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	492,309	2.90	332,128	2.33
EARNINGS PER COMMON SHARE:				
Basic	$ 1.09		$ 0.87	
Assuming dilution	$ 1.01		$ 0.82	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)				
Basic	452,150		380,675	
Assuming dilution	515,159		428,169	

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

SIX MONTHS ENDED:	June 30, 2007		June 30, 2006	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	2,672,042	8.25	2,697,204	9.66
Marketing sales	944,983	2.92	771,977	2.76
Service operations revenue	67,317	0.21	59,402	0.21
Total Revenues	3,684,342	11.38	3,528,583	12.63
OPERATING COSTS:				
Production expenses	295,275	0.91	240,089	0.86
Production taxes	95,090	0.29	89,296	0.32
General and administrative expenses	106,707	0.33	62,346	0.22
Marketing expenses	911,144	2.82	747,048	2.67
Service operations expense	44,062	0.14	30,104	0.11
Oil and natural gas depreciation, depletion and amortization	835,394	2.58	633,116	2.27
Depreciation and amortization of other assets	75,744	0.23	47,035	0.17
Employee retirement expense	—	—	54,753	0.20
Total Operating Costs	2,363,416	7.30	1,903,787	6.82
INCOME FROM OPERATIONS	1,320,926	4.08	1,624,796	5.81
OTHER INCOME (EXPENSE):				
Interest and other income	10,666	0.03	14,610	0.05
Interest expense	(162,470)	(0.50)	(146,114)	(0.52)
Gain on sale of investment	82,705	0.26	117,396	0.42
Total Other Income (Expense)	(69,099)	(0.21)	(14,108)	(0.05)
Income Before Income Taxes	1,251,827	3.87	1,610,688	5.76
Income Tax Expense:				
Current	—	—	—	—
Deferred	475,693	1.47	627,062	2.24
Total Income Tax Expense	475,693	1.47	627,062	2.24
NET INCOME	776,134	2.40	983,626	3.52
Preferred stock dividends	(51,672)	(0.16)	(37,040)	(0.13)
Loss on exchange/conversion of preferred stock	—	—	(10,556)	(0.04)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	724,462	2.24	936,030	3.35
EARNINGS PER COMMON SHARE:				
Basic	$ 1.60		$ 2.50	
Assuming dilution	$ 1.51		$ 2.27	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)				
Basic	451,757		374,683	
Assuming dilution	514,778		433,414	

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

	June 30, 2007	December 31, 2006
Cash	$ 3,870	$ 2,519
Other current assets	1,288,943	1,151,350
Total Current Assets	1,292,813	1,153,869
Property and equipment (net)	25,363,399	21,904,043
Other assets	1,039,534	1,359,255
Total Assets	$ 27,695,746	$ 24,417,167
Current liabilities	$ 2,212,552	$ 1,889,809
Long-term debt, net	9,416,650	7,375,548
Asset retirement obligation	208,194	192,772
Other long-term liabilities	530,798	390,108
Deferred tax liability	3,701,387	3,317,459
Total Liabilities	16,069,581	13,165,696
Stockholders' Equity	11,626,165	11,251,471
Total Liabilities & Stockholders' Equity	$ 27,695,746	$ 24,417,167
Common Shares Outstanding	471,087	457,434

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

	June 30, 2007	% of Total Book Capitalization	December 31, 2006	% of Total Book Capitalization
Long-term debt, net	$ 9,416,650	45%	$ 7,375,548	40%
Stockholders' equity	11,626,165	55%	11,251,471	60%
Total	$ 21,042,815	100%	$ 18,627,019	100%

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF SIX MONTHS ENDED JUNE 30, 2007 ADDITIONS TO OIL AND NATURAL GAS PROPERTIES
($ in 000's, except per unit amounts)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe
Exploration and development costs	$ 2,246,495	1,050,931[a]	$ 2.14
Acquisition of proved properties	397,140	201,748	$ 1.97
Subtotal	$ 2,643,635	1,252,679	$ 2.11
Divestitures	$ (228)	(117)	
Geological and geophysical costs	134,372	—	
Adjusted subtotal	$ 2,777,779	1,252,562	$ 2.22
Revisions – price	—	94,498	
Leasehold acquisition costs	$ 410,163	—	
Lease brokerage costs and recording fees	86,002	—	
Acquisition of unproved properties and other	460,269	—	
Leasehold and unproved property capitalized interest	118,295	—	
Adjusted subtotal	$ 3,852,508	1,347,060	$ 2.86
Tax basis step-up	$ 101,202	—	
Asset retirement obligation and other	8,455	—	
Total	$ 3,962,165	1,347,060	$ 2.94

(a) Includes positive performance revisions of 510 bcfe and excludes positive revisions of 94 bcfe resulting from oil and natural gas price increases between December 31, 2006 and June 30, 2007.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
SIX MONTHS ENDED JUNE 30, 2007
(unaudited)

	Mmcfe
Beginning balance, 01/01/07	8,955,614
Extensions and discoveries	540,961
Acquisitions	201,748
Divestitures	(117)
Revisions – performance	509,970
Revisions – price	94,498
Production	(323,674)
Ending balance, 6/30/07	9,979,000
Reserve replacement	1,347,060
Reserve replacement ratio [a]	416%

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

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

	THREE MONTHS ENDED June 30,		SIX MONTHS ENDED June 30,	
	2007	2006	2007	2006
Oil and Natural Gas Sales ($ in thousands):				
Oil sales	$ 139,672	$ 138,241	$ 252,825	$ 262,908
Oil derivatives – realized gains (losses)	12,259	(12,227)	30,107	(16,035)
Oil derivatives – unrealized gains (losses)	(14,843)	(2,564)	(26,900)	(3,899)
Total Oil Sales	137,088	123,450	256,032	242,974
Natural gas sales	1,058,653	774,259	1,946,642	1,714,577
Natural gas derivatives – realized gains (losses)	185,351	269,650	600,423	521,679
Natural gas derivatives – unrealized gains (losses)	166,432	19,024	(131,055)	217,974
Total Natural Gas Sales	1,410,436	1,062,933	2,416,010	2,454,230
Total Oil and Natural Gas Sales	$ 1,547,524	$ 1,186,383	$ 2,672,042	$ 2,697,204
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$ 60.10	$ 64.51	$ 56.60	$ 61.73
Natural gas ($ per mcf)	$ 6.78	$ 5.96	$ 6.56	$ 6.75
Natural gas equivalent ($ per mcfe)	$ 7.05	$ 6.40	$ 6.80	$ 7.08
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 65.37	$ 58.80	$ 63.34	$ 57.97
Natural gas ($ per mcf)	$ 7.97	$ 8.04	$ 8.58	$ 8.81
Natural gas equivalent ($ per mcfe)	$ 8.21	$ 8.20	$ 8.74	$ 8.89
Interest Expense ($ in thousands)				
Interest	$ 90,897	$ 73,834	$ 166,973	$ 146,732
Derivatives – realized (gains) losses	211	(1,163)	1,707	(2,407)
Derivatives – unrealized (gains) losses	(7,376)	785	(6,210)	1,789
Total Interest Expense	$ 83,732	$ 73,456	$ 162,470	$ 146,114

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

THREE MONTHS ENDED:	**June 30, 2007**	**June 30, 2006**
Beginning cash	$ 3,576	$ 38,286
Cash provided by operating activities	1,145,368	1,077,686
Cash (used in) investing activities	(2,133,906)	(1,823,996)
Cash provided by financing activities	988,832	1,074,294
Ending cash	3,870	366,270

SIX MONTHS ENDED:	**June 30, 2007**	**June 30, 2006**
Beginning cash	$ 2,519	$ 60,027
Cash provided by operating activities	2,121,900	2,045,144
Cash (used in) investing activities	(4,003,037)	(3,784,057)
Cash provided by financing activities	1,882,488	2,045,156
Ending cash	3,870	366,270

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

THREE MONTHS ENDED:	June 30, 2007	March 31, 2007	June 30, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,145,368	$ 976,532	$ 1,077,686
Adjustments:			
Changes in assets and liabilities	(69,046)	146,979	(163,520)
OPERATING CASH FLOW*	$ 1,076,322	$ 1,123,511	$ 914,166

*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:	June 30, 2007	March 31, 2007	June 30, 2006
NET INCOME	$ 518,145	$ 257,989	$ 359,903
Income tax expense	317,570	158,123	244,779
Interest expense	83,732	78,738	73,456
Depreciation and amortization of other assets	39,844	35,900	23,163
Oil and natural gas depreciation, depletion and amortization	442,063	393,331	328,159
EBITDA**	$ 1,401,354	$ 924,081	$ 1,029,460

**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:	June 30, 2007	March 31, 2007	June 30, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,145,368	$ 976,532	$ 1,077,686
Changes in assets and liabilities	(69,046)	146,979	(163,520)
Interest expense	83,732	78,738	73,456
Unrealized gains (losses) on oil and natural gas derivatives	151,589	(309,544)	16,460
Other non-cash items	89,711	31,376	25,378
EBITDA	$ 1,401,354	$ 924,081	$ 1,029,460

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

SIX MONTHS ENDED:	June 30, 2007	June 30, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,121,900	$ 2,045,144
Adjustments:		
Changes in assets and liabilities	77,933	(84,115)
OPERATING CASH FLOW*	$ 2,199,833	$ 1,961,029

*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.

SIX MONTHS ENDED:	June 30, 2007	June 30, 2006
NET INCOME	$ 776,134	$ 983,626
Income tax expense	475,693	627,062
Interest expense	162,470	146,114
Depreciation and amortization of other assets	75,744	47,035
Oil and natural gas depreciation, depletion and amortization	835,394	633,116
EBITDA**	$ 2,325,435	$ 2,436,953

**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:

SIX MONTHS ENDED:	June 30, 2007	June 30, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,121,900	$ 2,045,144
Changes in assets and liabilities	77,933	(84,115)
Interest expense	162,470	146,114
Unrealized gains (losses) on oil and natural gas derivatives	(157,955)	214,075
Other non-cash items	121,087	115,735
EBITDA	$ 2,325,435	$ 2,436,953

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

THREE MONTHS ENDED:	June 30, 2007	March 31, 2007	June 30, 2006
Net income available to common shareholders	$ 492,309	$ 232,153	$ 332,128
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	(98,559)	192,640	(9,720)
Gain on sale of investment, net of tax	(51,277)	—	—
Loss on conversion/exchange of preferred stock	—	—	9,547
Cumulative impact of income tax rate change	—	—	15,000
Legal settlement, net of tax	—	—	(7,192)
Adjusted net income available to common shareholders*	342,473	424,793	339,763
Preferred dividends	25,836	25,836	18,228
Total adjusted net income	$ 368,309	$ 450,629	$ 357,991
Weighted average fully diluted shares outstanding**	519,159	516,391	434,915
Adjusted earnings per share assuming dilution	$ 0.71	$ 0.87	$ 0.82

*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:	June 30, 2007	March 31, 2007	June 30, 2006
EBITDA	$ 1,401,354	$ 924,081	$ 1,029,460
Adjustments, before tax:			
Unrealized (gains) losses on oil and natural gas derivatives	(151,589)	309,544	(16,460)
Gain on sale of investment	(82,705)	—	—
Legal settlement	—	—	(11,600)
Adjusted ebitda*	$ 1,167,060	$ 1,233,625	$ 1,001,400

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

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

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

SIX MONTHS ENDED:	June 30, 2007	June 30, 2006
Net income available to common shareholders	$ 724,462	$ 936,030
Adjustments:		
Unrealized (gains) losses on derivatives, net of tax	94,081	(131,619)
Gain on sale of investment, net of tax	(51,277)	(72,786)
Loss on conversion/exchange of preferred stock	—	10,556
Employee retirement expense, net of tax	—	33,947
Cumulative impact of income tax rate change	—	15,000
Legal settlement, net of tax	—	(7,192)
Adjusted net income available to common shareholders*	767,266	783,936
Preferred dividends	51,672	37,040
Total adjusted net income	$ 818,938	$ 820,976
Weighted average fully diluted shares outstanding**	514,778	433,414
Adjusted earnings per share assuming dilution	$ 1.59	$ 1.89

*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)

SIX MONTHS ENDED:	June 30, 2007	June 30, 2006
EBITDA	$ 2,325,435	$ 2,436,953
Adjustments, before tax:		
Unrealized (gains) losses on oil and natural gas derivatives	157,955	(214,075)
Gain on sale of investment	(82,705)	(117,396)
Employee retirement expense	—	54,753
Legal settlement	—	(11,600)
Adjusted EBITDA*	$ 2,400,685	$ 2,148,635

*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 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 AUGUST 2, 2007

Quarter Ending September 30, 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 August 2, 2007, we are using the following key assumptions in our projections for the third quarter of 2007, the full-year 2007 and the full-year 2008.

The primary changes from our May 3, 2007 Outlook are in italicized bold in the table and are explained as follows:

1) We have provided our first guidance for the quarter ending September 30, 2007;
2) We have updated the projected effect of changes in our hedging positions;
3) Production and certain cost assumptions have been updated; and
4) Capital expenditure assumptions have been updated and specific detail has been provided by type of budgeted capital expenditure.

	Quarter Ending 9/30/2007	Year Ending 12/31/2007	Year Ending 12/31/2008
Estimated Production			
Oil – mbbls	***2,200***	***9,000***	***9,000***
Natural gas – bcf	***166.5 – 170.5***	***634 – 644***	***740.5 – 750.5***
Natural gas equivalent – bcfe	***179.5 – 183.5***	***688 – 698***	***794.5 – 804.5***
Daily natural gas equivalent midpoint – in mmcfe	***1,975***	***1,900***	***2,185***
NYMEX Prices [a] (for calculation of realized hedging effects only):			
Oil - $/bbl	***$65.00***	***$63.30***	***$65.00***
Natural gas - $/mcf	***$7.31***	***$7.28***	$7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	***$5.85***	***$6.24***	***$6.81***
Natural gas - $/mcf	***$1.42***	***$1.81***	***$1.46***
Estimated Differentials to NYMEX Prices:			
Oil - $/bbl	***7 – 9%***	***7 – 9%***	***7 – 9%***
Natural gas - $/mcf	***10 – 14%***	***10 – 14%***	***10 – 14%***
Operating Costs per Mcfe of Projected Production:			
Production expense	***$0.90 – 1.00***	$0.90 – 1.00	$0.90 – 1.00
Production taxes (generally ***5.5%*** of O&G revenues) [b]	***$0.35 – 0.40***	***$0.35 – 0.40***	***$0.35 – 0.40***
General and administrative	***$0.25 – 0.30***	$0.25 – 0.30	$0.25 – 0.30
Stock-based compensation (non-cash)	***$0.09 – 0.11***	$0.08 – 0.10	$0.10 – 0.12
DD&A of oil and natural gas assets	***$2.55 – 2.65***	$2.40 – 2.60	$2.50 – 2.70
Depreciation of other assets	***$0.24 – 0.28***	$0.24 – 0.28	***$0.24 – 0.28***
Interest expense[c]	***$0.55 – 0.60***	$0.60 – 0.65	***$0.55 – 0.60***
Other Income per Mcfe:			
Oil and natural gas marketing income	***$0.08 – 0.10***	***$0.08 – 0.10***	***$0.08 – 0.10***
Service operations income	***$0.06 – 0.08***	***$0.07 – 0.10***	***$0.07 – 0.10***
*Book Tax Rate (≈ **97%** deferred)*	***38%***	38%	38%
Equivalent Shares Outstanding – in millions:			
Basic	***454***	453	458
Diluted	***520***	519	524
Budgeted Capital Expenditures – in millions:			
Drilling	***$1,050 – 1,150***	***$4,300 – 4,500***	***$4,300 – 4,500***
Leasehold acquisition costs	***$100 – 200***	***$600 – 800***	***$600 – 800***
Geological and geophysical costs	***$50 – 75***	***$200 – 300***	***$200 – 300***
Total budgeted capital expenditures	***$1,200 – 1,425***	***$5,100 – 5,600***	***$5,100 – $5,600***

(a) Oil NYMEX prices have been updated for actual contract prices through June 2007 and natural gas NYMEX prices have been updated for actual contract prices through July 2007.
(b) Severance tax per mcfe is based on NYMEX prices of $65.00 per bbl of oil and $6.90 to $8.00 per mcf of natural gas during Q3 2007, $63.30 per bbl of oil and $6.90 to $8.00 per mcf of natural gas during calendar 2007 and $65.00 per bbl of oil and $6.90 to $8.00 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, Chesapeake receives a fixed price and pays 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) For knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
(iv) For written call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.
(v) Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.
(vi) A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires Chesapeake to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.
(vii) 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 Estimated Total Natural Gas Production	Total Gains from Lifted Swaps ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
2007:						
Q3	***85.9***	***$8.27***	***168.5***	***51%***	***$111.2***	***$0.66***
Q4	***95.2***	***$9.01***	***173.5***	***55%***	$116.8	***$0.67***
Q3-Q4 2007(1)	***181.1***	***$8.66***	***342.0***	***53%***	***$228.0***	***$0.67***
Total 2008(1)	***441.7***	***$9.33***	***745.5***	***59%***	$105.0	***$0.14***
Total 2009(1)	***115.9***	***$9.37***	***816.0***	***14%***	$3.9	$0.01

(1) Certain hedging arrangements include knockout swaps with knockout provisions at prices ranging from $5.25 to $6.50 covering 116 bcf in Q3-Q4 2007, $5.75 to $6.50 covering 222 bcf in 2008 and $5.90 to $6.50 covering 116 bcf in 2009.

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

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Collars as a % of Estimated Total Natural Gas Production
2007:					
Q3	22.1	$6.76	$8.20	***168.5***	***13%***
Q4	19.6	$7.13	$8.88	***173.5***	11%
Q3-Q4 2007(1)	41.7	$6.94	$8.52	***342.0***	***12%***
Total 2008(1)	26.8	$7.41	$9.40	***745.5***	4%
Total 2009(1)	18.3	$7.50	$10.72	***816.0***	2%

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 33 bcf in Q3-Q4 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $6.00 covering 18 bcf in 2009.

Note: Not shown above are written call options covering 51 bcf of production in Q3-Q4 2007 at a weighted average price of $9.45 for a weighted average premium of $0.55, 104 bcf of production in 2008 at a weighed average price of $10.39 for a weighted average premium of $0.68 and 72 bcf of production in 2009 at a weighed average price of $11.38 for a weighted average premium of $0.54.

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*:
Q3-Q4 2007	***78.5***	***0.37***	***18.4***	0.35
2008	118.6	0.27	***43.9***	0.35
2009	86.6	0.29	***36.5***	0.31
2010	—	—	***29.2***	***0.31***
2011	—	—	***29.2***	***0.32***
2012	***10.7***	***0.34***	—	—
Totals	***294.4***	$ ***0.31***	***157.2***	***$ 0.33***

* 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 ($255 million as of June 30, 2007). 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:						
Q3	10.6	$4.82	$8.45	($3.63)	***168.5***	***6%***
Q4	10.6	$4.82	$8.87	($4.05)	***173.5***	6%
Q3-Q4 2007	21.2	$4.82	$8.66	($3.84)	***342.0***	***6%***
Total 2008	38.4	$4.68	$8.02	($3.34)	***745.5***	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	***816.0***	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:						
Q3	1,656	$71.61	***2,230***	***74%***	$2.1	***$0.95***
Q4	1,656	$71.57	***2,300***	***72%***	$2.1	***$0.91***
Q3-Q4 2007(1)	3,312	$71.59	***4,530***	***73%***	$4.2	***$0.93***
Total 2008(1)	***6,680***	***$72.77***	***9,000***	***74%***	$4.8	***$0.54***
Total 2009(1)	***2,920***	***$77.58***	***9,000***	***32%***	—	—

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 1,472 mbbls in Q3-Q4 2007 and 3,112 mbbls in 2008 and from $52.50 to $60.00 covering 2,738 mbbls in 2009.

Note: Not shown above are written call options covering 916 mbbls of production in 2008 at a weighted average price of $75.00 for a weighted average premium of $5.03 and 1,460 mbbls of production in 2009 at a weighed average price of $75.00 for a weighted average premium of $5.96.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF MAY 3, 2007
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF AUGUST 2, 2007

Quarter Ending June 30, 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 May 3, 2007, we are using the following key assumptions in our projections for the second quarter of 2007, the full-year 2007 and the full-year 2008.

The primary changes from our February 22, 2007 Outlook are in italicized bold in the table and are explained as follows:

1) We have provided our first guidance for the quarter ending June 30, 2007;
2) We have updated the projected effect of changes in our hedging positions; and
3) Production, certain costs and capital expenditure assumptions have been updated.

	Quarter Ending 6/30/2007	Year Ending 12/31/2007	Year Ending 12/31/2008
Estimated Production			
Oil – mbbls	***2,100***	8,500	8,500
Natural gas – bcf	***145.5 – 149.5***	614 – 624	696 – 706
Natural gas equivalent – bcfe	***158 – 162***	665 – 675	747 – 757
Daily natural gas equivalent midpoint – in mmcfe	***1,758***	1,836	2,055
NYMEX Prices [(a)] *(for calculation of realized hedging effects only):*			
Oil - $/bbl	***$56.25***	***$56.73***	$56.25
Natural gas - $/mcf	***$7.52***	$7.32	$7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	***$12.08***	***$11.28***	***$12.43***
Natural gas - $/mcf	***$1.23***	***$1.78***	***$1.43***
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	***$0.90 – 1.00***	$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	***$0.25 – 0.30***	***$0.25 – 0.30***	***$0.25 – 0.30***
Stock-based compensation (non-cash)	***$0.08 – 0.10***	$0.08 – 0.10	***$0.10 – 0.12***
DD&A of oil and natural gas assets	***$2.54 – 2.60***	$2.40 – 2.60	$2.50 – 2.70
Depreciation of other assets	***$0.24 – 0.28***	$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 (≈ 95% deferred)	***38%***	38%	38%
Equivalent Shares Outstanding – in millions:			
Basic	***452***	453	458
Diluted	***517***	519	524
Capital Expenditures – in millions:			
Drilling, leasehold and seismic	***$1,200 –1,300***	***$5,000 – 5,200***	***$5,000 –5,200***

(a) Oil NYMEX prices have been updated for actual contract prices through March 2007 and natural gas NYMEX prices have been updated for actual contract prices through April 2007.
(b) Severance tax per mcfe is based on NYMEX prices of $56.25 per bbl of oil and $7.40 to $8.40 per mcf of natural gas during Q2 2007, $56.73 per bbl of oil and $7.40 to $8.40 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 Estimated Total Natural Gas Production	Total Gains from Lifted Swaps ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
2007:						
Q2	***67.2***	***$8.05***	147.5	***46%***	***$111.5***	***$0.76***
Q3	74.9	***$8.28***	***158.0***	47%	***$105.4***	***$0.67***
Q4	***84.5***	***$8.99***	***172.5***	***49%***	***$116.8***	***$0.68***
Q2-Q4 2007(1)	***226.6***	***$8.48***	***478.0***	***47%***	***$333.7***	***$0.70***
Total 2008(1)	***408.7***	***$9.31***	701.0	***58%***	$105.0	$0.15
Total 2009(1)	***79.4***	***$9.21***	750.0	***11%***	$3.9	$0.01

(1) Certain hedging arrangements include swaps with knockout prices ranging from $5.25 to $6.50 covering 152 bcf in Q2-Q4 2007, $5.75 to $6.50 covering 189 bcf in 2008 and $5.90 to $6.25 covering 79 bcf in 2009.

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

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Collars as a % of Estimated Total Natural Gas Production
2007:					
Q2	21.8	$6.76	$8.20	147.5	15%
Q3	22.1	$6.76	$8.20	***158.0***	14%
Q4	19.6	$7.13	$8.88	***172.5***	11%
Q2-Q4 2007(1)	63.5	$6.88	$8.41	***478.0***	***13%***
Total 2008(1)	***26.8***	***$7.41***	***$9.40***	701.0	***4%***
Total 2009(1)	***18.3***	***$7.50***	***$10.72***	***750.0***	***2%***

(1) Certain collar arrangements include knockout prices ranging from $5.00 to $6.00 covering 52 bcf in Q2-Q4 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $6.00 covering 18 bcf in 2009.

Note: Not shown above are written call options covering 63.3 bcf of production in Q2-Q4 2007 at a weighted average price of $9.48 for a weighted average premium of $0.54, 104.0 bcf of production in 2008 at a weighed average price of $10.39 for a weighted average premium of $0.68 and 53.8 bcf of production in 2009 at a weighed average price of $11.51 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*:
Q2-Q4 2007	***136.4***	***0.44***	***27.5***	0.35
2008	118.6	0.27	36.6	0.35
2009	86.6	0.29	***25.6***	0.31
Totals	***341.6***	$ 0.35	***89.7***	$ 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 ($293 million as of March 31, 2007). 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:						
Q2	10.5	$4.82	$8.48	($3.66)	147.5	7%
Q3	10.6	$4.82	$8.45	($3.63)	**158.0**	7%
Q4	10.6	$4.82	$8.87	($4.05)	**172.5**	6%
Q2-Q4 2007	31.7	$4.82	$8.60	($3.78)	***478.0***	7%
Total 2008	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:						
Q2	***1,638***	***$71.22***	***2,140***	***77%***	$2.1	***$0.98***
Q3	***1,656***	***$71.61***	2,140	***77%***	$2.1	$0.99
Q4	***1,656***	***$71.57***	2,145	***77%***	$2.1	$0.98
Q2-Q4 2007 (1)	***4,950***	***$71.47***	***6,425***	***77%***	$6.3	***$0.98***
Total 2008 (1)	***6,130***	***$72.61***	8,500	***72%***	$4.8	$0.57
Total 2009 (1)	***1,643***	***$75.41***	8,500	***19%***	—	—

(1) Certain hedging arrangements include swaps with knockout prices ranging from $45.00 to $60.00 covering 2,200 mbbls in Q2-Q4 2007, 2,928 mbbls in 2008 and 1,460 mbbls in 2009.

Note: Not shown above are written call options covering 732 mbbls of production in 2008 at a weighted average price of $75.00 for a weighted average premium of $4.90 and 730 mbbls of production in 2009 at a weighed average price of $75.00 for a weighted average premium of $5.90.