



## News Release

**FOR IMMEDIATE RELEASE  
JULY 27, 2006**

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**CHESAPEAKE ENERGY CORPORATION REPORTS STRONG RESULTS  
FOR THE 2006 SECOND QUARTER**

***Net Income Available to Common Shareholders Reaches \$332 Million on Revenue of  
\$1.6 Billion and Production of 143 Bcfe; Net Income Per Fully Diluted  
Common Share Increases 58% Over the 2005 Second Quarter***

***Total Production Growth Should Reach at Least 25% in 2006 and 11% in 2007,  
Including 10% Organic Production Growth in Each Year***

***Proved Reserves Reach Record Level of 8.1 Tcfe; Company Delivers First  
Half 2006 Reserve Replacement Rate of 308% From 860 Bcfe of  
Additions at a Drilling and Acquisition Cost of \$1.80 per Mcfe***

***Company Provides Detailed Review of its 14.0 Tcfe of Unproved Reserves Located  
on its 9.7 Million Net Acre U.S. Onshore Leasehold Position***

OKLAHOMA CITY, OKLAHOMA, JULY 27, 2006 – Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operating results for the second quarter of 2006. For the quarter, Chesapeake generated net income available to common shareholders of \$332.1 million (\$0.82 per fully diluted common share), operating cash flow of \$914.2 million (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of \$1.029 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of \$1.584 billion and production of 142.7 billion cubic feet of natural gas equivalent (bcfe). For the quarter, ebitda and net income per fully diluted common share increased 77% and 58% over the 2005 second quarter, respectively.

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

- an unrealized mark-to-market gain of \$9.7 million resulting from the company's oil and natural gas and interest rate hedging programs;
- a reversal of an accrual of \$7.2 million for production taxes as the result of the dismissal of certain severance tax claims;
- a \$15.0 million income tax accrual related to the recently adopted "margin" tax in Texas; and
- a reduction of net income available to common shareholders of \$9.5 million resulting from the exchange of two series of the company's preferred stock for common stock pursuant to tender offers made during the quarter.

Excluding the above-mentioned items and giving effect to common shares issued for preferred shares during the quarter, Chesapeake's net income to common shareholders in the second quarter of 2006 would have been \$339.8 million (\$0.82 per fully diluted common share) and ebitda would have been \$1.001 billion. The foregoing items do not affect the calculation of operating cash flow. For the quarter, adjusted ebitda and adjusted net income per fully diluted common share increased 77% and 64% over the 2005 second quarter. 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 18-21 of this release.

### **Key Operational and Financial Statistics Summarized Below for the 2006 Second Quarter**

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

	<u>Three Months Ended:</u>		
	<u>6/30/06</u>	<u>3/31/06</u>	<u>6/30/05</u>
Average daily production (in mmcfe)	1,568	1,519	1,244
Natural gas as % of total production	91	91	89
Natural gas production (in bcf)	129.8	124.1	101.1
Average realized natural gas price (\$/mcf) (a)	8.04	9.61	5.95
Oil production (in mbbls)	2,143	2,116	2,012
Average realized oil price (\$/bbl) (a)	58.80	57.12	42.82
Natural gas equivalent production (in bcfe)	142.7	136.8	113.2
Natural gas equivalent realized price (\$/mcfe) (a)	8.20	9.60	6.08
Marketing income (\$/mcfe)	.08	.10	.05
Service operations income (\$/mcfe)	.10	.11	-
Production expenses (\$/mcfe)	(.85)	(.87)	(.64)
Production taxes (\$/mcfe) (b)	(.24)	(.40)	(.42)
General and administrative costs (\$/mcfe) (c)	(.19)	(.17)	(.08)
Stock-based compensation (\$/mcfe)	(.05)	(.05)	(.02)
DD&A of oil and natural gas properties (\$/mcfe)	(2.30)	(2.23)	(1.85)
D&A of other assets (\$/mcfe)	(.16)	(.17)	(.10)
Interest expense (\$/mcfe) (a)	(.51)	(.52)	(.48)

Operating cash flow (\$ in millions) (d)	914.2	1,046.9	453.7
Operating cash flow (\$/mcf)	6.41	7.66	4.01
Adjusted ebitda (\$ in millions) (e)	1,001.4	1,147.2	564.6
Adjusted ebitda (\$/mcf)	7.02	8.39	4.99
Net income to common shareholders (\$ in millions)	332.1	603.9	179.2
Earnings per share – assuming dilution (\$)	0.82	1.44	0.52
Adjusted net income to common shareholders (\$ in millions) (f)	339.8	444.2	173.9
Adjusted earnings per share – assuming dilution (\$)	0.82	1.07	0.50

(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) current quarter includes an \$11.6 million reversal of an Oklahoma severance tax accrual

(c) excludes expenses associated with non-cash stock-based compensation

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

(e) 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 20.

(f) defined as net income as adjusted to remove the effects of certain items detailed on page 20.

### **Oil and Natural Gas Production Sets Record for 20<sup>th</sup> Consecutive Quarter; 2006 Second Quarter Average Daily Production Increases 26% and 3% Over Production in the 2005 Second Quarter and the 2006 First Quarter**

Daily production for the 2006 second quarter averaged 1.568 bcfe, an increase of 324 million cubic feet of natural gas equivalent (mmcf), or 26%, over the 1.244 bcfe of daily production in the 2005 second quarter and an increase of 49 mmcf, or 3.2%, over the 1.519 bcfe produced per day in the 2006 first quarter. Of the 324 mmcf increase in daily production from the year ago quarter, 45% was generated from organic drillbit growth and 55% was generated from acquisitions, with the company's trailing 12-month organic production growth rate calculated as 12.0%.

Of the 49 mmcf daily increase in sequential quarterly production, 95% was generated from organic drillbit growth and 5% was generated from acquisitions, with the company's sequential quarterly organic production growth rate calculated as 3.1%. Chesapeake is anticipating total production growth of at least 25% in 2006 and 11% in 2007, including organic growth rates of at least 10% each year. Please note that the company's production forecast for 2006 excludes any provision for possible production curtailments that the industry and Chesapeake may experience as a result of high pipeline pressures and/or early filling of U.S. natural gas storage facilities.

Chesapeake's 2006 second quarter production of 142.7 bcfe was comprised of 129.8 billion cubic feet of natural gas (bcf) (91% on a natural gas equivalent basis) and 2.14 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 1.568 bcfe consisted of 1.427 bcf of natural gas and 23,549 barrels (bbls) of oil. The 2006 second quarter was Chesapeake's 20th consecutive quarter of sequential U.S. production growth. Over these 20 quarters, Chesapeake's U.S. production has increased 296%, for an average compound quarterly growth rate of 7.1% and an average compound annual growth rate of 31.7%.

## **Chesapeake Continues Industry's Most Active Drilling Program With Drilling Success Rate Over 97%**

Chesapeake's exploratory and development drilling programs and production enhancement operations on its existing and acquired properties continue to produce operational results that distinguish the company among its peers. During the 2006 first half, Chesapeake continued the industry's most active drilling program and drilled 613 gross (496 net) operated wells and participated in another 801 gross (88 net) wells operated by other companies. The company's drilling success rate was 97% for company-operated wells and 99% for non-operated wells. During the 2006 first half, Chesapeake invested \$1.097 billion in operated wells (using an average of 82 operated rigs), \$241 million in non-operated wells (using an average of 75 non-operated rigs), \$324 million to acquire new leasehold (exclusive of leases acquired through acquisitions) and \$72 million to acquire new 3-D seismic data.

### **During the First Half of 2006, Oil and Natural Gas Proved Reserves Reach Record Level of 8.1 Tcfe; Drilling and Acquisition Costs Average \$1.80 per Mcfe as Company Adds 860 Bcfe for a Reserve Replacement Rate of 308%**

Chesapeake began 2006 with estimated proved reserves of 7.521 trillion cubic feet of natural gas equivalent (tcfe) and ended the second quarter with 8.101 tcfe, an increase of 580 bcfe, or 7.7%. During the 2006 first half, Chesapeake replaced its 279 bcfe of production with an estimated 860 bcfe of new proved reserves, for a reserve replacement rate of 308%. Reserve replacement through the drillbit was 590 bcfe, or 211% of production (including 352 bcfe of positive performance revisions and 196 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and June 30, 2006) and 69% of the total increase. Reserve replacement through the acquisition of proved reserves was 269 bcfe, or 97% of production and 31% of the total increase.

Total costs incurred during the 2006 first half, including drilling, completion, acquisition, seismic, leasehold, capitalized internal costs, non-cash tax basis step-up from corporate acquisitions, asset retirement obligations and all other miscellaneous costs capitalized to oil and natural gas properties, were \$3.6 billion. The company's total drilling and acquisition costs were \$1.80 per thousand cubic feet of natural gas equivalent (mcfe), excluding costs of \$1.6 billion for leasehold and unproved properties acquired during the period and \$93 million relating primarily to tax basis step-up and asset retirement obligations, as well as downward revisions of proved reserves from lower natural gas prices. Excluding the same costs as described above, Chesapeake's exploration and development costs through the drillbit were \$1.70 per mcfe during the 2006 first half while reserve replacement costs through acquisitions of proved reserves were \$1.84 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves is presented on page 16 of this release.

As of June 30, 2006, the estimated future net cash flows of Chesapeake's proved reserves, before income taxes and discounted at 10% (PV-10), were \$15.0 billion using field differential adjusted prices of \$69.10 per barrel of oil (bbl) (based on a NYMEX quarter-ending price of \$73.86 per bbl) and \$5.72 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-ending price of \$6.09 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 securities and other non-current assets) was \$1.8 billion as of June 30, 2006.

Chesapeake's PV-10 changes by approximately \$310 million for every \$0.10 per mcf change in natural gas prices and approximately \$49 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 June 30, 2006 PV-10 value to the standardized measure at such date. 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.

#### **Average Prices Realized, Hedging Results and Hedging Positions Detailed**

Average prices realized during the 2006 second quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were \$58.80 per bbl and \$8.04 per mcf, for a realized natural gas equivalent price of \$8.20 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the second quarter were a negative \$6.19 per bbl and a negative \$0.84 per mcf. Realized gains and losses from oil and natural gas hedging activities during the quarter generated a \$5.71 loss per bbl and a \$2.08 gain per mcf, for a 2006 second quarter realized hedging gain of \$257.4 million, or \$1.80 per mcfe. Chesapeake's total realized hedging gains in the first half of 2006 were \$505.6 million, or \$1.81 per mcfe.

Chesapeake has hedged a substantial level of its production through 2008 in order to capture attractive returns from recent acquisitions and to help secure strong margins and profitability on the company's drilling program. The following tables compare Chesapeake's hedged production volumes (including only swaps and also including the hedges assumed in the CNR acquisition) as of July 27, 2006 to those as of June 5, 2006.

### Swap Positions as of July 27, 2006

Quarter or Year	Natural Gas		Oil	
	% Hedged	\$ NYMEX	% Hedged	\$ NYMEX
2006 3Q	93%	\$8.85	87%	\$64.83
2006 4Q	87%	\$9.50	86%	\$65.64
2006 Total Remaining	90%	\$9.17	87%	\$65.25
2007 Total	72%	\$9.88	73%	\$71.42
2008 Total	57%	\$9.37	63%	\$71.45

### Swap Positions as of June 5, 2006

Quarter or Year	Natural Gas		Oil	
	% Hedged	\$ NYMEX	% Hedged	\$ NYMEX
2006 3Q	93%	\$8.85	84%	\$63.90
2006 4Q	86%	\$9.50	85%	\$63.76
2006 Total Remaining	89%	\$9.17	84%	\$63.83
2007 Total	69%	\$9.86	56%	\$68.79
2008 Total	55%	\$9.34	48%	\$69.50

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

The company's updated 2006 and 2007 forecasts are attached to this release in an Outlook dated July 27, 2006 labeled as Schedule "A", which begins on page 22. This Outlook has been changed from the Outlook dated June 5, 2006 (attached as Schedule "B", which begins on page 26) to reflect various updated information.

### Chesapeake Increases Cost Inflation Hedges through Additional Oilfield Service Investments

Chesapeake recently agreed to purchase one of the leading drilling contractors in the Appalachian Basin. The company is currently utilizing two of the contractor's 15 rigs and through this acquisition will gain enhanced operational flexibility in expanding activity levels in the basin. This acquisition bolsters the scale and operating capabilities of the company's 100% owned drilling rig subsidiary, Nomac Drilling Corporation. To date, Chesapeake has invested approximately \$400 million to build or acquire 57 drilling rigs (including the pending acquisition of the Appalachian Basin drilling contractor) and is building 22 additional rigs. In total, Chesapeake's drilling rig fleet should reach 79 rigs by the end of the 2007 first quarter, which would rank Nomac as one of the six largest drilling rig contractors in the U.S.

Chesapeake's direct rig ownership is complemented by its \$63 million in investments in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain owns four rigs and has ordered another six rigs for delivery later in 2006 and 2007. Chesapeake's rig investments have served as an effective hedge to rising service costs and have also provided competitive advantages in making acquisitions and in developing its own leasehold on a more timely and efficient basis.

**Chesapeake's Leasehold and 3-D Seismic Inventories Now 9.7 Million Net Acres and 12.9 Million Acres; Risked Unproved Reserves in the Company's Inventory Now 14.0 Tcfe, Bringing Total Reserve Base to 22.1 Tcfe**

Chesapeake attributes its strong drilling results and organic growth rates during 2006 (and in this decade) to management's early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry – people, land and science. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff by over 450% to nearly 800 employees. Today, the company has more than 4,100 employees, of which approximately 70% work in the company's E&P operations and approximately 30% work in the company's oilfield service operations.

Since 2000, Chesapeake has invested \$4.7 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be one of the largest inventories of onshore leasehold (9.7 million net acres) and 3-D seismic (12.9 million acres) in the U.S. On this leasehold, the company has an estimated 24,000 net drilling locations, representing an approximate 10-year inventory of drilling projects, on which it believes it can develop approximately 3.3 tcf of proved undeveloped reserves and approximately 14.0 tcf of unproved reserves. Adding the company's total proved reserves of 8.1 tcf to its estimated 14.0 tcf of unproved reserves brings Chesapeake's estimated total reserves to 22.1 tcf.

**Company Provides Detailed Information on Its Four Gas Resource Play Types**

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 position 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, 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 10.0 million acres of 3-D seismic data. In these plays, Chesapeake owns 3.0 million net acres on which it has an estimated 1.0 tcf of proved undeveloped reserves, an estimated 2.4 tcf of risked unproved reserves and is currently utilizing 31 operated drilling rigs (up to 32 by year-end) to further develop its inventory of approximately 2,800 drillsites. Two of Chesapeake's most important conventional gas resource plays are described below.

- *South Texas*: Located primarily in Zapata County, Texas, Chesapeake's South Texas assets are currently producing approximately 145 mmcf per day and the company is currently utilizing six rigs (up to seven by year-end) to develop its 140,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in South Texas are an estimated 211 bcfe and its risked unproved reserves are an estimated 300 bcfe after applying a 75% risk factor and assuming an additional 325 net wells are drilled in the years ahead. The company's expected economics for vertical South Texas wells are \$3.0 million to develop 2.0 bcfe on 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 currently producing approximately 80 mmcf per day from the Mountain Front area and is currently utilizing four rigs (four at year-end also) to develop its 120,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Mountain Front are an estimated 65 bcfe and its risked unproved reserves are an estimated 200 bcfe after applying a 70% risk factor and assuming an additional 80 net wells are drilled in the years ahead. The company's expected economics for vertical Mountain Front wells are \$8.0 million to develop 4.0 bcfe on 320 acre spacing.

**Unconventional Gas Resource Plays** - In its unconventional gas resource areas, Chesapeake owns 1.1 million net acres on which it has an estimated 1.7 tcf of proved undeveloped reserves, an estimated 6.0 tcf of risked unproved reserves and is currently utilizing 51 operated drilling rigs (up to 69 by year-end) to further develop its inventory of approximately 9,000 net drillsites. Four of Chesapeake's most important unconventional gas resource plays are described below.

- *Fort Worth Barnett Shale (North Texas)*: This play is the largest unconventional gas resource play in the U.S. and Chesapeake believes it is the third largest producer of natural gas and the third most active driller as well as the second largest leasehold owner in Tarrant and Johnson Counties (the sweet spot of the horizontally developed "Tier 1" area). Chesapeake is currently producing approximately 130 mmcf per day from the Fort Worth Barnett Shale and is currently utilizing 15 rigs (up to 25 by year-end) to develop its 165,000 net acres of leasehold located primarily in the Tier 1 area. Chesapeake's proved undeveloped reserves in the Fort Worth Barnett are an estimated 594 bcfe and its risked unproved reserves are an estimated 3.4 tcf after applying a 25% risk factor and assuming an additional 2,200 net wells are drilled in the years ahead.

The company's expected economics for horizontal Barnett Shale wells are \$2.7 million to develop 2.4 bcfe on 55 acre spacing.

- Sahara (Primarily Mississippi, Chester, Hunton formations in Northwest Oklahoma): In this vast play that extends across five counties in northwestern Oklahoma, Chesapeake believes it is the largest producer of natural gas, the most active driller and the largest leasehold owner in the area. Chesapeake is currently producing approximately 130 mmcfe per day in the Sahara area and is currently utilizing 12 rigs (up to 16 by year-end) to develop its 500,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in Sahara are an estimated 397 bcfe and its risked unproved reserves are an estimated 1.8 tcfe after applying a 25% risk factor and assuming an additional 4,900 net wells are drilled in the years ahead. The company's expected economics 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 believes it is one of the 10 largest producers of natural gas, the third most active driller and one of the largest leasehold owners in the area. Chesapeake is currently producing approximately 100 mmcfe per day in the Ark-La-Tex area and is currently utilizing 14 rigs (up to 17 by year-end) to further develop its 125,000 net acres of leasehold. Chesapeake's unconventional proved undeveloped reserves in the Ark-La-Tex region are an estimated 369 bcfe and its unconventional risked unproved reserves are an estimated 425 bcfe after applying a 40% risk factor and assuming an additional 1,100 net wells are drilled in the years ahead. The company's expected economics for medium-depth vertical unconventional Ark-La-Tex wells are \$1.6 million to develop 1.0 bcfe on approximately 60 acre spacing.
- Granite, Atoka and Cherokee Washes (Western Oklahoma and Texas Panhandle): Chesapeake believes it is the largest producer of natural gas, the most active driller and the largest leasehold owner in the Wash plays. Chesapeake is currently producing approximately 110 mmcfe per day from these plays and is currently utilizing 10 rigs (up to 11 by year-end) to further develop its 115,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Wash plays are an estimated 304 bcfe and its risked unproved reserves are an estimated 300 bcfe after applying a 50% risk factor and assuming an additional 525 net wells are drilled in the years ahead. The company's expected economics for vertical Wash wells are \$2.8 million to develop 1.4 bcfe on 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 2.2 million net acres on which it has an estimated 100 bcfe of proved undeveloped reserves, an estimated 3.8 tcf of risked unproved reserves and is currently utilizing 10 operated drilling rigs (up to 23 rigs by year-end) to further develop its inventory of approximately 2,600 net drillsites. Five of Chesapeake's most important emerging unconventional gas resource plays are described below.

- **Fayetteville Shale (Arkansas):** In this region of rapidly growing importance to Chesapeake, the company believes it is now the largest leasehold owner in the play (second largest in the most currently prospective area of the play). Chesapeake is currently producing approximately 2.0 mmcf per day from the Fayetteville Shale and is currently utilizing two rigs (up to eight by year-end) to further develop its 1.0 million net acres of leasehold (300,000 net acres in the most currently prospective area of the play to date). Chesapeake's proved undeveloped reserves in the Fayetteville are an estimated 18 bcfe and its risked unproved reserves are an estimated 2.0 tcf after applying an 85% risk factor and assuming an additional 2,000 net wells are drilled in the years ahead. The company's expected economics for horizontal Fayetteville Shale wells are \$2.5 million to develop 1.2 bcfe on 80 acre spacing.
- **Deep Haley (Primarily Strawn, Atoka, Morrow formations in West Texas):** In this West Texas Delaware Basin area of increasing value to Chesapeake, the company believes it is now the second largest leasehold owner. Chesapeake is currently producing approximately 30 mmcf per day from the Deep Haley area and is currently utilizing four rigs (up to eight by year-end) to further develop its 225,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in Deep Haley are an estimated 59 bcfe and its risked unproved reserves are an estimated 650 bcfe after applying an 80% risk factor and assuming an additional 140 net wells are drilled in the years ahead. The company's expected economics for vertical Deep Haley wells are \$10.5 million to develop 7.0 bcfe on 320 acre spacing.
- **Delaware Basin Shales (Primarily Barnett and Woodford formations in West Texas):** Chesapeake's most significant land acquisition activities during the 2006 second quarter took place in the Delaware Basin Barnett and Woodford Shale play in far West Texas. In this promising play, Chesapeake believes it has become the second largest leasehold owner (and the largest in what it believes is the most prospective area of the play). Chesapeake is currently producing approximately 1.0 mmcf per day from the Delaware Basin Barnett and Woodford Shales and is currently utilizing two rigs (up to four by year-end) to further develop its 385,000 net acres of leasehold. Chesapeake has not yet booked any proved reserves in the Delaware Basin shales plays and its risked unproved reserves are an estimated 600 bcfe after applying a 90% risk factor and assuming an additional 240 net wells are drilled in the years ahead. The

company's expected economics for Delaware Basin vertical Barnett and Woodford Shale wells are \$4.5 million to develop 3.0 bcfe on 160 acre spacing.

- **Caney and Woodford Shales (Oklahoma Arkoma Basin):** Chesapeake believes it is now the third largest leasehold owner in the Caney and Woodford Shale play, one of the most promising unconventional gas plays in the Oklahoma portion of the Arkoma Basin. The company is currently producing approximately 7.0 mmcfe per day from the Caney and Woodford Shales and is currently utilizing one rig to drill its first operated horizontal Woodford Shale well on its 100,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the play are an estimated 10 bcfe and its risked unproved reserves are an estimated 300 bcfe after applying a 70% risk factor and assuming an additional 170 net wells are drilled in the years ahead. The company's expected economics for horizontal Woodford Shale wells are \$4.0 million to develop 2.2 bcfe on 160 acre spacing.
- **Deep Bossier (East Texas and Northern Louisiana):** Chesapeake believes it has become one of the top three leasehold owners in the emerging Deep Bossier play. The company is currently producing approximately 1.0 mmcfe per day in the Deep Bossier play and is currently utilizing one rig (one or two by year-end) to further develop its 190,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Deep Bossier play are an estimated 6.0 bcfe and its risked unproved reserves are an estimated 200 bcfe after applying a 90% risk factor and assuming an additional 60 net wells are drilled in the years ahead. The company's expected economics for Deep Bossier wells are \$10.0 million to develop 5.0 bcfe on 320 acre spacing.

**Appalachian Basin Gas Resource Plays** - In this core area of the company's operations, play types range from conventional to unconventional to emerging gas resource in various Devonian Shale and other formations. Chesapeake is the largest leasehold owner in the region with 3.4 million net acres that were primarily acquired from CNR in November 2005. The company is currently producing approximately 120 mmcfe per day and is currently utilizing nine rigs (up to 11 rigs by year-end) to further develop its extensive leasehold position. In Appalachia, Chesapeake has an estimated 468 bcfe of proved undeveloped reserves and its risked unproved reserves are an estimated 1.8 tcf after applying a 35% risk factor and assuming an additional 9,100 net wells are drilled in the years ahead. The company's expected economics for vertical Devonian Shale wells are \$0.425 million to develop 0.3 bcfe on 160 acre spacing.

In addition, Chesapeake continues to actively develop various conventional, unconventional and emerging unconventional plays not described above. These areas are located throughout the company's operations and in which the company continues to actively generate new prospects and acquire additional leasehold.

## Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to again report outstanding financial and operational results for the 2006 second quarter. The company delivered top-tier organic production growth and impressive profit margins as strong oil and natural gas price realizations far exceeded modest cost inflation. We have also opportunistically hedged service costs and a substantial portion of our anticipated production through 2008 at exceptional prices in order to ensure strong profitability. This position differentiates Chesapeake among many companies in the industry that may face margin compression as natural gas markets digest short-term excess natural gas supplies caused in large part by limited storage capacity and exceptionally warm weather last winter.

In light of continued strong returns available through the drillbit on our extensive prospect inventory, we continue to increase our industry-leading U.S. drilling activity to accelerate development of our substantial unproved reserve base. We currently have 101 operated rigs working, up from an average of 73 operated rigs in 2005, and we anticipate increasing our drilling activity to approximately 135 operated rigs by year-end 2006. This increase in drilling activity creates the potential for increased proved reserves and production levels in 2006 and 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 capital and mitigating financial and operational risks through 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, July 28, 2006 at 9:00 a.m. EDT. The telephone number to access the conference call is **913-981-5543** and the confirmation code is **4119635**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 am EDT. For those unable to participate in the conference call, a replay will be available for audio playback from noon EDT, July 28, 2006 through midnight EDT on August 10, 2006. The number to access the conference call replay is **719-457-0820** and the passcode for the replay is **4119635**. 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](http://www.chkenergy.com) and selecting the "News & Events" section. The webcast of the conference call will be available on our website indefinitely.

*This press release and the accompanying Outlooks include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of oil and natural gas reserves, expected oil and natural gas production and future expenses, projections of future oil and natural gas prices, planned capital expenditures for drilling, leasehold*

acquisitions and seismic data, and statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair value of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in the Prospectus dated June 27, 2006 for our offering of 7.625% Senior Notes due 2013 filed with the Securities and Exchange Commission on June 29, 2006. They include the volatility of oil and natural gas prices; the limitations our level of indebtedness may have on our financial flexibility; our ability to compete effectively against strong independent oil and natural gas companies and majors; the availability of capital on an economic basis to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures; uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities; our ability to effectively consolidate and integrate acquired properties and operations; unsuccessful exploration and development drilling; declines in the values of our oil and natural gas properties resulting in ceiling test write-downs; lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; the negative impact lower oil and natural gas prices could have on our ability to borrow; and drilling and operating risks. We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Our production forecasts exclude provisions for possible production curtailments that the industry and Chesapeake may experience as a result of high pipeline pressures and/or early filling of U.S. natural gas storage facilities. Also, our internal estimates of reserves, particularly those in the properties recently acquired or proposed to be acquired where we may have limited review of data or experience with the reserves, may be subject to revision and may be different from estimates by our external reservoir engineers at year-end. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties.

The SEC has generally permitted oil and natural gas companies, in filings made with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms "probable", "possible" or "unproved" to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

**Chesapeake Energy Corporation is the second largest independent producer of natural gas in the U.S. Headquartered in Oklahoma City, the company's operations are focused on exploratory and developmental drilling and corporate and property acquisitions in the Mid-Continent, Permian Basin, South Texas, Texas Gulf Coast, Barnett Shale, Ark-La-Tex and Appalachian Basin regions of the United States. The company's Internet address is [www.chkenergy.com](http://www.chkenergy.com).**

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

THREE MONTHS ENDED:	June 30, 2006		June 30, 2005	
	\$	\$/mcf	\$	\$/mcf
<b>REVENUES:</b>				
Oil and natural gas sales	1,186,383	8.32	772,401	6.83
Marketing sales	367,610	2.57	275,617	2.43
Service operations revenue	<u>30,023</u>	<u>0.21</u>	<u>—</u>	<u>—</u>
Total Revenues	<u>1,584,016</u>	<u>11.10</u>	<u>1,048,018</u>	<u>9.26</u>
<b>OPERATING COSTS:</b>				
Production expenses	120,697	0.85	72,333	0.64
Production taxes	33,923	0.24	47,253	0.42
General and administrative expenses	33,555	0.24	11,788	0.10
Marketing expenses	355,688	2.48	270,003	2.39
Service operations expense	15,667	0.11	—	—
Oil and natural gas depreciation, depletion and amortization	328,159	2.30	209,371	1.85
Depreciation and amortization of other assets	<u>23,163</u>	<u>0.16</u>	<u>11,807</u>	<u>0.10</u>
Total Operating Costs	<u>910,852</u>	<u>6.38</u>	<u>622,555</u>	<u>5.50</u>
<b>INCOME FROM OPERATIONS</b>	<u>673,164</u>	<u>4.72</u>	<u>425,463</u>	<u>3.76</u>
<b>OTHER INCOME (EXPENSE):</b>				
Interest and other income	4,974	0.03	2,005	0.02
Interest expense	(73,456)	(0.51)	(53,902)	(0.48)
Loss on repurchases or exchanges of Chesapeake debt	<u>—</u>	<u>—</u>	<u>(68,400)</u>	<u>(0.60)</u>
Total Other Income (Expense)	<u>(68,482)</u>	<u>(0.48)</u>	<u>(120,297)</u>	<u>(1.06)</u>
<b>Income Before Income Taxes</b>	604,682	4.24	305,166	2.70
<b>Income Tax Expense:</b>				
Current	—	—	—	—
Deferred	<u>244,779</u>	<u>1.72</u>	<u>111,387</u>	<u>0.99</u>
Total Income Tax Expense	<u>244,779</u>	<u>1.72</u>	<u>111,387</u>	<u>0.99</u>
<b>NET INCOME</b>	<u>359,903</u>	<u>2.52</u>	<u>193,779</u>	<u>1.71</u>
Preferred stock dividends	(18,228)	(0.12)	(9,859)	(0.09)
Loss on exchange/conversion of preferred stock	<u>(9,547)</u>	<u>(0.07)</u>	<u>(4,743)</u>	<u>(0.04)</u>
<b>NET INCOME AVAILABLE TO COMMON SHAREHOLDERS</b>	<u>332,128</u>	<u>2.33</u>	<u>179,177</u>	<u>1.58</u>
<b>EARNINGS PER COMMON SHARE:</b>				
Basic	<u>\$ 0.87</u>		<u>\$ 0.58</u>	
Assuming dilution	<u>\$ 0.82</u>		<u>\$ 0.52</u>	
<b>WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)</b>				
Basic	<u>380,675</u>		<u>311,181</u>	
Assuming dilution	<u>428,169</u>		<u>364,063</u>	

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

SIX MONTHS ENDED:	June 30, 2006		June 30, 2005	
	\$	\$/mcf	\$	\$/mcf
<b>REVENUES:</b>				
Oil and natural gas sales	2,697,204	9.66	1,311,343	6.01
Marketing sales	771,977	2.76	520,125	2.39
Service operations revenue	<u>59,402</u>	<u>0.21</u>	<u>—</u>	<u>—</u>
<b>Total Revenues</b>	<u><b>3,528,583</b></u>	<u><b>12.63</b></u>	<u><b>1,831,468</b></u>	<u><b>8.40</b></u>
<b>OPERATING COSTS:</b>				
Production expenses	240,089	0.86	141,895	0.65
Production taxes	89,296	0.32	83,211	0.38
General and administrative expenses	62,346	0.22	23,855	0.11
Marketing expenses	747,048	2.67	507,279	2.33
Service operations expense	30,104	0.11	—	—
Oil and natural gas depreciation, depletion and amortization	633,116	2.27	390,339	1.79
Depreciation and amortization of other assets	47,035	0.17	21,889	0.10
Employee retirement expense	<u>54,753</u>	<u>0.20</u>	<u>—</u>	<u>—</u>
<b>Total Operating Costs</b>	<u><b>1,903,787</b></u>	<u><b>6.82</b></u>	<u><b>1,168,468</b></u>	<u><b>5.36</b></u>
<b>INCOME FROM OPERATIONS</b>	<u><b>1,624,796</b></u>	<u><b>5.81</b></u>	<u><b>663,000</b></u>	<u><b>3.04</b></u>
<b>OTHER INCOME (EXPENSE):</b>				
Interest and other income	14,610	0.05	5,362	0.02
Interest expense	(146,114)	(0.52)	(97,030)	(0.44)
Gain on sale of investment	117,396	0.42	—	—
Loss on repurchases or exchanges of Chesapeake debt	<u>—</u>	<u>—</u>	<u>(69,300)</u>	<u>(0.32)</u>
<b>Total Other Income (Expense)</b>	<u><b>(14,108)</b></u>	<u><b>(0.05)</b></u>	<u><b>(160,968)</b></u>	<u><b>(0.74)</b></u>
<b>Income Before Income Taxes</b>	1,610,688	5.76	502,032	2.30
<b>Income Tax Expense:</b>				
Current	—	—	—	—
Deferred	<u>627,062</u>	<u>2.24</u>	<u>183,243</u>	<u>0.84</u>
<b>Total Income Tax Expense</b>	<u><b>627,062</b></u>	<u><b>2.24</b></u>	<u><b>183,243</b></u>	<u><b>0.84</b></u>
<b>NET INCOME</b>	<u><b>983,626</b></u>	<u><b>3.52</b></u>	<u><b>318,789</b></u>	<u><b>1.46</b></u>
Preferred stock dividends	(37,040)	(0.13)	(15,322)	(0.07)
Loss on exchange/conversion of preferred stock	<u>(10,556)</u>	<u>(0.04)</u>	<u>(4,743)</u>	<u>(0.02)</u>
<b>NET INCOME AVAILABLE TO COMMON SHAREHOLDERS</b>	<u><u><b>936,030</b></u></u>	<u><u><b>3.35</b></u></u>	<u><u><b>298,724</b></u></u>	<u><u><b>1.37</b></u></u>
<b>EARNINGS PER COMMON SHARE:</b>				
Basic	<u>\$ 2.50</u>		<u>\$ 0.96</u>	
Assuming dilution	<u>\$ 2.27</u>		<u>\$ 0.88</u>	
<b>WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)</b>				
Basic	<u>374,683</u>		<u>310,523</u>	
Assuming dilution	<u>433,414</u>		<u>356,478</u>	

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

	June 30, 2006	December 31, 2005
Cash	\$ 366,270	\$ 60,027
Other current assets	<u>1,289,467</u>	<u>1,123,370</u>
<b>Total Current Assets</b>	<u>1,655,737</u>	<u>1,183,397</u>
Property and equipment (net)	17,775,369	14,411,887
Other assets	<u>629,945</u>	<u>523,178</u>
<b>Total Assets</b>	<u>\$ 20,061,051</u>	<u>\$ 16,118,462</u>
Current liabilities	\$ 1,776,469	\$ 1,964,088
Long term debt	6,330,115	5,489,742
Asset retirement obligation	171,430	156,593
Other long term liabilities	357,120	528,738
Deferred tax liability	<u>2,435,731</u>	<u>1,804,978</u>
<b>Total Liabilities</b>	<u>11,070,865</u>	<u>9,944,139</u>
<b>STOCKHOLDERS' EQUITY</b>	<u>8,990,186</u>	<u>6,174,323</u>
<b>TOTAL LIABILITIES &amp; STOCKHOLDERS' EQUITY</b>	<u>\$ 20,061,051</u>	<u>\$ 16,118,462</u>
<b>COMMON SHARES OUTSTANDING</b>	<u>418,876</u>	<u>370,190</u>

**CHESAPEAKE ENERGY CORPORATION**  
**RECONCILIATION OF SIX MONTHS ENDED JUNE 30, 2006 ADDITIONS TO OIL AND NATURAL GAS PROPERTIES**  
(\$ in 000's, except per unit amounts)  
(unaudited)

	Cost	Reserves (in mmcfe)	\$/mcf
Exploration and development costs	\$ 1,338,205	786,027 <sup>(a)</sup>	\$ 1.70
Acquisition of proved properties	<u>494,278</u>	<u>269,239</u>	\$ 1.84
<b>Subtotal</b>	<u>1,832,483</u>	<u>1,055,266</u>	\$ 1.74
Divestitures	(73)	(89)	
Geological and geophysical costs	<u>71,675</u>	<u>—</u>	
<b>Adjusted subtotal</b>	1,904,085	1,055,177	\$ 1.80
Revisions – price	—	(195,541)	
Acquisition of unproved properties	1,256,132	—	
Leasehold acquisition costs	<u>323,856</u>	<u>—</u>	
<b>Adjusted subtotal</b>	<u>3,484,073</u>	<u>859,636</u>	\$ 4.05
Tax basis step-up	81,373	—	
Asset retirement obligation and other	<u>11,774</u>	<u>—</u>	
<b>Total</b>	<u>\$ 3,577,220</u>	<u>859,636</u>	\$ 4.16

(a) Includes positive performance revisions of 352 bcfe and excludes downward revisions of 196 bcfe resulting from natural gas price declines between December 31, 2005 and June 30, 2006.

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

	Mmcfe
Beginning balance, 12/31/05	7,520,690
Extensions and discoveries	434,414
Acquisitions	269,239
Divestitures	(89)
Revisions – performance	351,613
Revisions – price	(195,541)
Production	<u>(279,428)</u>
<b>Ending balance, 6/30/06</b>	<u>8,100,898</u>
Reserve replacement	859,636
Reserve replacement rate	308%

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

	THREE MONTHS ENDED		SIX MONTHS ENDED	
	June 30,		June 30,	
	2006	2005	2006	2005
<b>Oil and Natural Gas Sales (\$ in thousands):</b>				
Oil sales	\$ 138,241	\$ 96,798	\$ 262,908	\$ 176,742
Oil derivatives – realized gains (losses)	(12,227)	(10,650)	(16,035)	(17,717)
Oil derivatives – unrealized gains (losses)	<u>(2,564)</u>	<u>10,900</u>	<u>(3,899)</u>	<u>(1,942)</u>
Total Oil Sales	<u>123,450</u>	<u>97,048</u>	<u>242,974</u>	<u>157,083</u>
Natural gas sales	774,259	635,901	1,714,577	1,171,678
Natural gas derivatives – realized gains (losses)	269,650	(33,702)	521,679	13,713
Natural gas derivatives – unrealized gains (losses)	<u>19,024</u>	<u>73,154</u>	<u>217,974</u>	<u>(31,131)</u>
Total Natural Gas Sales	<u>1,062,933</u>	<u>675,353</u>	<u>2,454,230</u>	<u>1,154,260</u>
Total Oil and Natural Gas Sales	<u>\$ 1,186,383</u>	<u>\$ 772,401</u>	<u>\$ 2,697,204</u>	<u>\$ 1,311,343</u>
<b>Average Sales Price (excluding gains (losses) on derivatives):</b>				
Oil (\$ per bbl)	\$ 64.51	\$ 48.11	\$ 61.73	\$ 47.03
Natural gas (\$ per mcf)	\$ 5.96	\$ 6.29	\$ 6.75	\$ 6.00
Natural gas equivalent (\$ per mcfe)	\$ 6.40	\$ 6.47	\$ 7.08	\$ 6.19
<b>Average Sales Price (excluding unrealized gains (losses) on derivatives):</b>				
Oil (\$ per bbl)	\$ 58.80	\$ 42.82	\$ 57.97	\$ 42.32
Natural gas (\$ per mcf)	\$ 8.04	\$ 5.95	\$ 8.81	\$ 6.07
Natural gas equivalent (\$ per mcfe)	\$ 8.20	\$ 6.08	\$ 8.89	\$ 6.17
<b>Interest Expense (\$ in thousands)</b>				
Interest	\$ 73,834	\$ 54,710	\$ 146,732	\$ 102,003
Derivatives – realized (gains) losses	(1,163)	(675)	(2,407)	(1,796)
Derivatives – unrealized (gains) losses	<u>785</u>	<u>(133)</u>	<u>1,789</u>	<u>(3,177)</u>
Total Interest Expense	<u>\$ 73,456</u>	<u>\$ 53,902</u>	<u>\$ 146,114</u>	<u>\$ 97,030</u>

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

THREE MONTHS ENDED:	June 30, 2006	June 30, 2005
Cash provided by operating activities	\$ 1,077,686	\$ 507,232
Cash (used in) investing activities	(1,823,996)	(1,365,941)
Cash provided by financing activities	1,074,294	858,709
<hr/>		
SIX MONTHS ENDED:	June 30, 2006	June 30, 2005
Cash provided by operating activities	\$ 2,045,144	\$ 1,019,917
Cash (used in) investing activities	(3,784,057)	(2,539,878)
Cash provided by financing activities	2,045,156	1,513,065

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

THREE MONTHS ENDED:	June 30, 2006	March 31, 2006	June 30, 2005
<b>CASH PROVIDED BY OPERATING ACTIVITIES</b>	\$ 1,077,686	\$ 967,458	\$ 507,232
<b>Adjustments:</b>			
<b>Changes in assets and liabilities</b>	<u>(163,520)</u>	<u>79,405</u>	<u>(53,498)</u>
<b>OPERATING CASH FLOW*</b>	<u>\$ 914,166</u>	<u>\$ 1,046,863</u>	<u>\$ 453,734</u>

\*Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of an oil and 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, 2006	March 31, 2006	June 30, 2005
<b>NET INCOME</b>	\$ 359,903	\$ 623,723	\$ 193,779
<b>Income tax expense</b>	244,779	382,283	111,387
<b>Interest expense</b>	73,456	72,658	53,902
<b>Depreciation and amortization of other assets</b>	23,163	23,872	11,807
<b>Oil and natural gas depreciation, depletion and amortization</b>	<u>328,159</u>	<u>304,957</u>	<u>209,371</u>
<b>EBITDA**</b>	<u>\$ 1,029,460</u>	<u>\$ 1,407,493</u>	<u>\$ 580,246</u>

\*\*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, 2006	March 31, 2006	June 30, 2005
<b>CASH PROVIDED BY OPERATING ACTIVITIES</b>	\$ 1,077,686	\$ 967,458	\$ 507,232
<b>Changes in assets and liabilities</b>	(163,520)	79,405	(53,498)
<b>Interest expense</b>	73,456	72,658	53,902
<b>Unrealized gains (losses) on oil and natural gas derivatives</b>	16,460	197,615	84,054
<b>Other non-cash items</b>	<u>25,378</u>	<u>90,357</u>	<u>(11,444)</u>
<b>EBITDA</b>	<u>\$ 1,029,460</u>	<u>\$ 1,407,493</u>	<u>\$ 580,246</u>

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

SIX MONTHS ENDED:	June 30, 2006	June 30, 2005
<b>CASH PROVIDED BY OPERATING ACTIVITIES</b>	\$ 2,045,144	\$ 1,019,917
<b>Adjustments:</b>		
<b>Changes in assets and liabilities</b>	<u>(84,115)</u>	<u>(61,561)</u>
<b>OPERATING CASH FLOW*</b>	<u>\$ 1,961,029</u>	<u>\$ 958,356</u>

\*Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of an oil and 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, 2006	June 30, 2005
<b>NET INCOME</b>	\$ 983,626	\$ 318,789
<b>Income tax expense</b>	627,062	183,243
<b>Interest expense</b>	146,114	97,030
<b>Depreciation and amortization of other assets</b>	47,035	21,889
<b>Oil and natural gas depreciation, depletion and amortization</b>	<u>633,116</u>	<u>390,339</u>
<b>EBITDA**</b>	<u>\$ 2,436,953</u>	<u>\$ 1,011,290</u>

\*\*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, 2006	June 30, 2005
<b>CASH PROVIDED BY OPERATING ACTIVITIES</b>	\$ 2,045,144	\$ 1,019,917
<b>Changes in assets and liabilities</b>	(84,115)	(61,561)
<b>Interest expense</b>	146,114	97,030
<b>Unrealized gains (losses) on oil and natural gas derivatives</b>	214,075	(33,073)
<b>Other non-cash items</b>	<u>115,735</u>	<u>(11,023)</u>
<b>EBITDA</b>	<u>\$ 2,436,953</u>	<u>\$ 1,011,290</u>

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

THREE MONTHS ENDED:	June 30, 2006	March 31, 2006	June 30, 2005
Net income available to common shareholders	\$ 332,128	\$ 603,902	\$ 179,177
<b>Adjustments:</b>			
Loss on conversion/exchange of preferred stock	9,547	1,009	4,743
Unrealized (gains) losses on derivatives, net of tax	(9,720)	(121,899)	(53,458)
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 debt, net of tax	—	—	43,434
<b>Adjusted net income available to common shareholders*</b>	<u>339,763</u>	<u>444,173</u>	<u>173,896</u>
Preferred dividends	<u>18,228</u>	<u>18,812</u>	<u>9,859</u>
<b>Total adjusted net income</b>	<u>\$ 357,991</u>	<u>\$ 462,985</u>	<u>\$ 183,755</u>
<b>Weighted average fully diluted shares outstanding**</b>	434,915	431,723	366,677
<b>Adjusted earnings per share assuming dilution</b>	<u>\$ 0.82</u>	<u>\$ 1.07</u>	<u>\$ 0.50</u>

\*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, 2006	March 31, 2006	June 30, 2005
EBITDA	\$ 1,029,460	\$ 1,407,493	\$ 580,246
<b>Adjustments, before tax:</b>			
Unrealized (gains) losses on oil and natural gas derivatives	(16,460)	(197,615)	(84,054)
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 debt	—	—	68,400
<b>Adjusted EBITDA*</b>	<u>\$ 1,001,400</u>	<u>\$ 1,147,235</u>	<u>\$ 564,592</u>

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

SIX MONTHS ENDED:	June 30, 2006	June 30, 2005
Net income available to common shareholders	\$ 936,030	\$ 298,724
<b>Adjustments:</b>		
Loss on conversion/exchange of preferred stock	10,556	4,743
Unrealized (gains) losses on derivatives, net of tax	(131,619)	18,985
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 debt, net of tax	<u>—</u>	<u>44,006</u>
Adjusted net income available to common shareholders*	783,936	366,458
Preferred dividends	<u>37,040</u>	<u>15,322</u>
<b>Total adjusted net income</b>	<b>\$ <u>820,976</u></b>	<b>\$ <u>381,780</u></b>
<b>Weighted average fully diluted shares outstanding**</b>	<b>433,414</b>	<b>359,136</b>
<b>Adjusted earnings per share assuming dilution</b>	<b>\$ <u>1.89</u></b>	<b>\$ <u>1.06</u></b>

\*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, 2006	June 30, 2005
EBITDA	\$ 2,436,953	\$ 1,011,290
<b>Adjustments, before tax:</b>		
Unrealized (gains) losses on oil and natural gas derivatives	(214,075)	33,073
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 debt	<u>—</u>	<u>69,300</u>
<b>Adjusted EBITDA*</b>	<b>\$ <u>2,148,635</u></b>	<b>\$ <u>1,113,663</u></b>

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

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

## SCHEDULE "A"

### CHESAPEAKE'S OUTLOOK AS OF JULY 27, 2006

**Quarter Ending September 30, 2006; Year Ending December 31, 2006; Year Ending December 31, 2007.**

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of July 27, 2006, we are using the following key assumptions in our projections for the third quarter of 2006, the full-year 2006 and the full-year 2007.

The primary changes from our June 5, 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) Production, certain costs and capital expenditure assumptions have been updated;
- 3) We have shown our projections for the quarter ending September 30, 2006 for the first time.

	Quarter Ending 9/30/2006	Year Ending 12/31/2006	Year Ending 12/31/2007
<i>Estimated Production</i> <sup>(a)</sup> :			
Oil – mbbls	<b>2,000</b>	<b>8,400</b>	<b>8,400</b>
Natural gas – bcf	<b>136 – 140</b>	<b>531 – 541</b>	<b>595 – 605</b>
Natural gas equivalent – bcfe	<b>148 – 152</b>	581 – 591	<b>645 – 655</b>
Daily natural gas equivalent midpoint –in mmcfe	<b>1,630</b>	1,605	<b>1,781</b>
<i>NYMEX Prices</i> <sup>(b)</sup> (for calculation of realized hedging effects only):			
Oil - \$/bbl	<b>\$56.25</b>	<b>\$61.67</b>	<b>\$56.25</b>
Natural gas - \$/mcf	<b>\$6.96</b>	<b>\$7.57</b>	<b>\$7.50</b>
<i>Estimated Realized Hedging Effects</i> (based on assumed NYMEX prices above):			
Oil - \$/bbl	<b>\$7.26</b>	<b>\$1.92</b>	<b>\$11.43</b>
Natural gas - \$/mcf	<b>\$1.89</b>	<b>\$1.99</b>	<b>\$1.89</b>
<i>Estimated Differentials to NYMEX Prices:</i>			
Oil - \$/bbl	<b>6 – 8%</b>	<b>7 – 9%</b>	6 – 8%
Natural gas - \$/mcf	<b>8 – 12%</b>	<b>10 – 15%</b>	9 – 13%
<i>Operating Costs per Mcfe of Projected Production:</i>			
Production expense	<b>\$0.85 – 0.95</b>	\$0.85 – 0.95	\$0.90 – 1.00
Production taxes (generally 6.0% of O&G revenues) <sup>(c)</sup>	<b>\$0.38 – 0.42</b>	\$0.41 – 0.46	<b>\$0.41 – 0.46</b>
General and administrative	<b>\$0.15 – 0.20</b>	\$0.15 – 0.20	\$0.15 – 0.20
Stock-based compensation (non-cash)	<b>\$0.05 – 0.07</b>	\$0.06 – 0.08	\$0.08 – 0.10
DD&A of oil and natural gas assets	<b>\$2.35 – 2.40</b>	\$2.30 – 2.40	\$2.40 – 2.50
Depreciation of other assets	<b>\$0.18 – 0.22</b>	\$0.18 – 0.22	\$0.24 – 0.28
Interest expense <sup>(d)</sup>	<b>\$0.55 – 0.59</b>	<b>\$0.54 – 0.58</b>	<b>\$0.60 – 0.65</b>
<i>Other Income per Mcfe:</i>			
Marketing and other income	<b>\$0.02 – 0.04</b>	\$0.04 – 0.06	\$0.04 – 0.06
Service operations income	<b>\$0.10 – 0.12</b>	<b>\$0.08 – 0.12</b>	\$0.10 – 0.15
<i>Book Tax Rate</i> (≈ 95% deferred)	<b>38%</b>	<b>38%</b>	<b>38%</b>
<i>Equivalent Shares Outstanding:</i>			
Basic	<b>418 mm</b>	<b>397 mm</b>	<b>423 mm</b>
Diluted	<b>484 mm</b>	<b>459 mm</b>	<b>488 mm</b>
<i>Capital Expenditures:</i>			
Drilling, leasehold and seismic	<b>\$900 – 1,100 mm</b>	<b>\$3,700 – 4,000 mm</b>	<b>\$3,800 – 4,100 mm</b>

- (a) Production forecast for Q3 2006 and calendar 2006 excludes provisions for possible production curtailments that the industry and Chesapeake may experience as a result of high pipeline pressures and/or early filling of U.S. natural gas storage facilities.
- (b) Oil NYMEX prices have been updated for actual contract prices through June 2006 and natural gas NYMEX prices have been updated for actual contract prices through July 2006.
- (c) Severance tax per mcf is based on NYMEX prices of \$56.25 per bbl of oil and \$6.80 to \$7.60 per mcf of natural gas during Q3 2006, \$57.35 per bbl of oil and \$7.50 to \$8.50 per mcf of natural gas during calendar 2006 and \$56.25 per bbl of oil and \$7.50 to \$8.50 per mcf of natural gas during calendar 2007.
- (d) 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 losses from the derivative transactions are reflected as adjustments to oil and natural gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and natural gas sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e. because of temporary fluctuations in value) are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and natural gas sales.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales.

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

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Gain (Loss) from Locked Swaps	Avg. NYMEX Price Including Open & Locked Positions	Assuming Natural Gas Production in Bcf's of:	% Hedged Open Swap Positions as a % of Estimated Total Natural Gas Production
2006:						
Q1	93.8	\$10.81	-\$0.09	\$10.72	124.1	76%
Q2	101.4	\$8.82	-\$0.05	\$8.77	<b>129.8</b>	78%
Q3	117.9	\$8.80	-\$0.05	\$8.75	<b>138.0</b>	85%
Q4	114.9	\$9.46	-\$0.04	\$9.42	<b>144.1</b>	<b>80%</b>
Total 2006 <sup>(1)</sup>	428.0	\$9.42	-\$0.05	\$9.37	<b>536.0</b>	80%
Total 2007	<b>392.1</b>	<b>\$9.99</b>	<b>-\$0.03</b>	<b>\$9.96</b>	<b>600.0</b>	<b>65%</b>
Total 2008	<b>329.4</b>	<b>\$9.53</b>	-	<b>\$9.53</b>	<b>642.0</b>	<b>51%</b>
Total 2009	3.7	\$9.02	-	\$9.02	<b>687.0</b>	1%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$3.75 to \$5.50 covering 43.0 bcf in 2006, \$5.75 to \$6.50 covering 53.9 bcf in 2007 and \$5.75 to \$6.50 covering 69.5 bcf in 2008, respectively.

Note: Not shown above are collars covering 0.2 bcf of production in 2006 at a weighted average floor and ceiling of \$6.00 and \$9.70 and call options covering 7.3 bcf of production in 2006 at a weighted average price of \$12.50, 25.6 bcf of production in 2007 at a weighted average price of \$10.53 and 7.3 bcf of production in 2008 at a weighted average price of \$12.50.

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

	<u>Mid-Continent</u>		<u>Appalachia</u>	
	<u>Volume in Bcf's</u>	<u>NYMEX less*:</u>	<u>Volume in Bcf's</u>	<u>NYMEX plus*:</u>
2006	130.1	\$ 0.32	-	\$ -
2007	137.2	0.33	36.5	0.35
2008	118.6	0.27	36.6	0.35
2009	86.6	0.29	18.2	0.31
Totals	<u>472.5</u>	<u>\$ 0.30</u>	<u>91.3</u>	<u>\$ 0.34</u>

\* 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 (\$469 million as of June 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:**

	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)	% Hedged	
					Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
2006:						
Q1	7.9	\$4.91	\$12.14	(\$7.23)	124.1	6%
Q2	10.5	\$4.86	\$9.97	(\$5.11)	<b>129.8</b>	8%
Q3	10.6	\$4.86	\$9.95	(\$5.09)	<b>138.0</b>	8%
Q4	10.6	\$4.86	\$10.38	(\$5.52)	<b>144.1</b>	7%
Total 2006	39.6	\$4.87	\$10.51	(\$5.64)	<b>536.0</b>	7%
Total 2007	42.0	\$4.82	\$9.18	(\$4.36)	<b>600.0</b>	7%
Total 2008	38.4	\$4.67	\$8.01	(\$3.34)	<b>642.0</b>	6%
Total 2009	18.3	\$5.18	\$7.28	(\$2.10)	<b>687.0</b>	3%

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

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

	Open Swaps in mbbls	Avg. NYMEX Strike Price	% Hedged	
			Assuming Oil Production in mbbls of:	Open Swap Positions as % of Total Estimated Production
2006:				
Q1	1,109.5	\$60.03	2,116	52%
Q2	1,379.5	\$61.85	<b>2,143</b>	<b>64%</b>
Q3	<b>1,747.0</b>	<b>\$64.83</b>	<b>2,000</b>	<b>87%</b>
Q4	<b>1,840.0</b>	<b>\$65.64</b>	<b>2,141</b>	<b>86%</b>
Total 2006 <sup>(1)</sup>	<b>6,076.0</b>	<b>\$63.52</b>	<b>8,400</b>	<b>72%</b>
Total 2007	<b>6,110.0</b>	<b>\$71.42</b>	<b>8,400</b>	<b>73%</b>
Total 2008	<b>5,032.0</b>	<b>\$71.45</b>	8,000	<b>63%</b>
Total 2009	182.5	\$66.10	8,000	2%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$40.00 to \$60.00 covering 654.5 mbbls in 2006, \$45.00 to \$60.00 covering 1,460.0 mbbls in 2007 and \$45.00 to \$60.00 covering 1,098.0 mbbls in 2008, respectively.

## SCHEDULE "B"

### CHESAPEAKE'S PREVIOUS OUTLOOK AS OF JUNE 5, 2006 (PROVIDED FOR REFERENCE ONLY)

### NOW SUPERSEDED BY OUTLOOK AS OF JULY 27, 2006

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

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of June 5, 2006, we are using the following key assumptions in our projections for the second quarter of 2006, the full-year 2006 and the full-year 2007.

The primary changes from our May 1, 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) Production, certain costs and capital expenditures have increased as a result of the acquisitions announced today; and
- 3) Share count has been adjusted to reflect our tender offer to convert our 4.125% preferred stock and 5.0% preferred stock to common stock, recent repurchases of common stock and an expected preferred equity offering in the near future.

	Quarter Ending <u>6/30/2006</u>	Year Ending <u>12/31/2006</u>	Year Ending <u>12/31/2007</u>
<i>Estimated Production:</i>			
Oil – mbbls	2,000	8,000	8,000
Natural gas – bcf	127 – 132	<b>533 – 543</b>	<b>592 – 602</b>
Natural gas equivalent – bcfe	139 – 144	<b>581 – 591</b>	<b>640 – 650</b>
Daily natural gas equivalent midpoint –in mmcfe	1,555	<b>1,605</b>	<b>1,767</b>
<i>NYMEX Prices <sup>(a)</sup> (for calculation of realized hedging effects only):</i>			
Oil - \$/bbl	<b>\$58.39</b>	<b>\$56.72</b>	<b>\$52.50</b>
Natural gas - \$/mcf	<b>\$7.16</b>	<b>\$7.54</b>	<b>\$7.00</b>
<i>Estimated Realized Hedging Effects (based on assumed NYMEX prices above):</i>			
Oil - \$/bbl	<b>\$2.62</b>	<b>\$4.83</b>	<b>\$9.39</b>
Natural gas - \$/mcf	<b>\$1.68</b>	<b>\$2.00</b>	<b>\$2.19</b>
<i>Estimated Differentials to NYMEX Prices:</i>			
Oil - \$/bbl	6 – 8%	6 – 8%	6 – 8%
Natural gas - \$/mcf	8 – 12%	<b>9 – 13%</b>	<b>9 – 13%</b>
<i>Operating Costs per Mcfe of Projected Production:</i>			
Production expense	\$0.85 – 0.95	\$0.85 – 0.95	\$0.90 – 1.00
Production taxes (generally 6.0% of O&G revenues) <sup>(b)</sup>	<b>\$0.40 – 0.45</b>	\$0.41 – 0.46	\$0.36 – 0.41
General and administrative	\$0.15 – 0.20	\$0.15 – 0.20	\$0.15 – 0.20
Stock-based compensation (non-cash)	\$0.05 – 0.07	\$0.06 – 0.08	\$0.08 – 0.10
DD&A of oil and natural gas assets	\$2.25 – 2.35	<b>\$2.30 – 2.40</b>	<b>\$2.40 – 2.50</b>
Depreciation of other assets	\$0.16 – 0.20	<b>\$0.18 – 0.22</b>	<b>\$0.24 – 0.28</b>
Interest expense <sup>(c)</sup>	\$0.52 – 0.57	\$0.52 – 0.57	\$0.53 – 0.58
<i>Other Income per Mcfe:</i>			
Marketing and other income	\$0.02 – 0.04	<b>\$0.04 – 0.06</b>	<b>\$0.04 – 0.06</b>
Service operations income	\$0.10 – 0.15	\$0.10 – 0.15	\$0.10 – 0.15
<i>Book Tax Rate (≈ 95% deferred)</i>	<b>37.5%</b>	<b>37.5%</b>	<b>37.5%</b>
<i>Equivalent Shares Outstanding:</i>			
Basic	<b>379 mm</b>	<b>380 mm</b>	<b>389 mm</b>
Diluted	<b>434 mm</b>	<b>441 mm</b>	<b>452 mm</b>

*Capital Expenditures:*

Drilling, leasehold and seismic

**\$900 – 1,000 mm    \$3,500 – 3,800 mm    \$3,500 – 3,800 mm**

- (a) Oil NYMEX prices have been updated for actual contract prices through April 2006 and natural gas NYMEX prices have been updated for actual contract prices through May 2006.
- (b) Severance tax per mcf is based on NYMEX prices of \$58.39 per bbl of oil and \$7.20 to \$8.20 per mcf of natural gas during Q2 2006, \$56.72 per bbl of oil and \$7.35 to \$8.35 per mcf of natural gas during calendar 2006, and \$52.50 per bbl of oil and \$6.50 to \$7.50 per mcf of natural gas during calendar 2007.
- (c) Does not include gains or losses on interest rate derivatives (SFAS 133).

**Commodity Hedging Activities**

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

- (i) For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- (ii) For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.
- (iii) Basis protection swaps are arrangements that guarantee a price differential of oil or natural gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and natural gas prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to oil and natural gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and natural gas sales in the month of related production. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e. because of temporary fluctuations in value) are reported currently in the consolidated statement of operations as unrealized gains (losses) within oil and natural gas sales.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales.

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

					% Hedged	
	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Gain (Loss) from Locked Swaps	Avg. NYMEX Price Including Open & Locked Positions	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
2006:						
Q1	93.8	\$10.81	-\$0.09	\$10.72	124.1	76%
Q2	101.4	\$8.82	-\$0.05	\$8.77	129.5	78%
Q3	117.9	\$8.80	-\$0.05	\$8.75	<b>138.5</b>	<b>85%</b>
Q4	114.9	\$9.46	-\$0.04	\$9.42	<b>145.9</b>	<b>79%</b>
Total 2006 <sup>(1)</sup>	428.0	\$9.42	-\$0.05	\$9.37	<b>538.0</b>	80%
Total 2007 <sup>(1)</sup>	<b>370.2</b>	<b>\$9.98</b>	<b>-\$0.04</b>	<b>\$9.94</b>	<b>597.0</b>	<b>62%</b>
Total 2008 <sup>(1)</sup>	<b>311.1</b>	<b>\$9.50</b>	-	<b>\$9.50</b>	<b>637.0</b>	<b>49%</b>
Total 2009	3.7	\$9.02	-	\$9.02	<b>682.0</b>	1%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$3.75 to \$5.50 covering 43.0 bcf in 2006, \$5.75 to \$6.50 covering 32.0 bcf in 2007 and \$5.75 to \$6.50 covering 51.2 bcf in 2008, respectively.

Note: Not shown above are collars covering 0.2 bcf of production in 2006 at a weighted average floor and ceiling of \$6.00 and \$9.70 and call options covering 7.3 bcf of production in 2006 at a weighted average price of \$12.50, 25.6 bcf of production in 2007 at a weighted average price of \$10.53 and 7.3 bcf of production in 2008 at a weighted average price of \$12.50.

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

	<b>Mid-Continent</b>		<b>Appalachia</b>	
	Volume in Bcf's	NYMEX less*:	Volume in Bcf's	NYMEX plus*:
2006	130.1	\$ 0.32	-	\$ -
2007	137.2	0.33	<b>36.5</b>	<b>0.35</b>
2008	118.6	0.27	<b>36.6</b>	<b>0.35</b>
2009	86.6	0.29	18.2	0.31
Totals	<u>472.5</u>	<u>\$ 0.30</u>	<u><b>91.3</b></u>	<u><b>\$ 0.34</b></u>

\* weighted average

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

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

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

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	% Hedged	
					Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
2006:						
Q1	7.9	\$4.91	\$12.14	(\$7.23)	124.1	6%
Q2	10.5	\$4.86	\$9.97	(\$5.11)	129.5	8%
Q3	10.6	\$4.86	\$9.95	(\$5.09)	<b>138.5</b>	8%
Q4	10.6	\$4.86	\$10.38	(\$5.52)	<b>145.9</b>	<b>7%</b>
Total 2006	39.6	\$4.87	\$10.51	(\$5.64)	<b>538.0</b>	7%
Total 2007	42.0	\$4.82	\$9.18	(\$4.36)	<b>597.0</b>	7%
Total 2008	38.4	\$4.67	\$8.01	(\$3.34)	<b>637.0</b>	6%
Total 2009	18.3	\$5.18	\$7.28	(\$2.10)	<b>682.0</b>	3%

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

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

	Open Swaps in mbbls	Avg. NYMEX Strike Price	% Hedged	
			Assuming Oil Production in mbbls of:	Open Swap Positions as % of Total Estimated Production
2006:				
Q1	1,109.5	\$60.03	2,116	52%
Q2	1,379.5	\$61.85	2,000	69%
Q3	1,625.0	\$63.90	1,942	84%
Q4	1,656.0	\$63.76	1,942	85%
Total 2006 <sup>(1)</sup>	5,770.0	\$62.63	8,000	72%
Total 2007	<b>4,452.0</b>	<b>\$68.79</b>	8,000	<b>56%</b>
Total 2008	<b>3,843.0</b>	<b>\$69.50</b>	8,000	<b>48%</b>
Total 2009	182.5	\$66.26	8,000	2%

(1) Certain hedging arrangements include swaps with knockout prices ranging from \$40.00 to \$42.00 covering 501.5 mbbls in 2006, \$45.00 covering 182.5 mbbls in 2007 and \$45.00 covering 183.0 mbbls in 2008, respectively.