News Release

FOR IMMEDIATE RELEASE
FEBRUARY 21, 2013

CHESAPEAKE ENERGY CORPORATION REPORTS FINANCIAL AND OPERATIONAL RESULTS FOR THE 2012 FOURTH QUARTER AND FULL YEAR

Company Reports 2012 Fourth Quarter Net Income Available to Common Stockholders of $257 Million, or $0.39 per Share, Adjusted Net Income Available to Common Stockholders of $153 Million, or $0.26 per Share, and Adjusted Ebitda and Operating Cash Flow of $1.1 Billion

2012 Fourth Quarter Production Totals 362 Bcfe for an Average of 3.9 Bcfe per Day, an Increase of 9% Year over Year; 2012 Fourth Quarter Liquids Production Totals 147,500 Bbls per Day, an Increase of 39% Year over Year

Company Reports 2012 Year-End Proved Reserves of 15.7 Tcfe; Adds Proved Reserves of 5.0 Tcfe in 2012

OKLAHOMA CITY, FEBRUARY 21, 2013 – Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operational results for the 2012 fourth quarter and full year. For the 2012 fourth quarter, Chesapeake reported net income available to common stockholders of $257 million ($0.39 per fully diluted common share), ebitda of $1.299 billion (defined as net income (loss) before income taxes, interest expense and depreciation, depletion and amortization), operating cash flow of $1.146 billion (defined as cash flow from operating activities before changes in assets and liabilities) and production of 362 billion cubic feet of natural gas equivalent (bcfe). For the 2012 full year, Chesapeake reported a net loss available to common stockholders of $940 million, or a loss of $1.46 per fully diluted common share, ebitda of $1.914 billion, operating cash flow of $4.069 billion and production of 1.422 trillion cubic feet of natural gas equivalent (tcfe).

The company's 2012 fourth quarter and full year results include various items that are generally not included in published estimates of the company's financial results by securities analysts. Excluding such items, Chesapeake reported adjusted net income available to common stockholders of $153 million, or $0.26 per fully diluted common share, and adjusted ebitda of $1.089 billion for the 2012 fourth quarter and adjusted net income available to common stockholders of $285 million, or $0.61 per fully diluted common share, and adjusted ebitda of $3.754 billion for the 2012 full year. The primary excluded items from the 2012 fourth quarter and full year reported results are the following:

- a noncash after-tax impairment charge of $2.022 billion for the full year related to the carrying value of natural gas and oil properties;
- an after-tax charge of $122 million related to the full repayment of the company's May 2012 term loans for the fourth quarter and full year;
- net unrealized noncash after-tax mark-to-market gains of $78 million for the fourth quarter and $347 million for the full year resulting from the company's natural gas, oil and natural gas liquids (NGL) and interest rate hedging programs;

INVESTOR CONTACTS:
Jeffrey L. Mobley, CFA
(405) 767-4763
jeff.mobley@chk.com
Gary T. Clark, CFA
(405) 935-6741
gary.clark@chk.com

MEDIA CONTACTS:
Michael Kehs
(405) 935-2560
michael.kehs@chk.com
Jim Gipson
(405) 935-1310
jim.gipson@chk.com

CHESAPEAKE ENERGY CORPORATION
6100 North Western Avenue
P.O. Box 18496
Oklahoma City, OK 73154

- net after-tax gains of $166 million for the fourth quarter and $163 million for the full year related to gains and losses on sales, including a $176 million after-tax gain on the sale of the company's midstream subsidiary for the fourth quarter and full year;
- noncash after-tax charges of $36 million for the fourth quarter and $208 million for the full year related to the impairment of certain fixed assets; and
- net after-tax gains of $19 million for the fourth quarter and $622 million for the full year related to certain investments, including a $629 million gain for the full year related to the sale of all of the company's interests in Access Midstream Partners, L.P. (NYSE:ACMP).

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 provided on pages 18 - 21 of this release.

Management Comments

Steven C. Dixon, Chesapeake's Chief Operating Officer, said, "We continue to deliver on our liquids growth targets, led by a year-over-year increase of nearly 40,000 barrels per day in oil production. We achieved this despite the sale of nearly 18,000 barrels per day of oil production associated with our exit from the Permian Basin during the 2012 third and fourth quarters. We believe this performance ranks Chesapeake among the top three organic oil growth stories in the industry for 2012. I am very proud of what our team has accomplished thus far and look forward to driving further liquids production growth and capital efficiencies in 2013."

Domenic J. Dell'Osso, Jr., Chesapeake's Chief Financial Officer, added, "Chesapeake delivered strong results during the 2012 fourth quarter. I am pleased to reaffirm our 2013 guidance for liquids production growth and drilling and completion capital expenditures, while at the same time reducing our cost guidance for many significant categories. Additionally, we are reaffirming the commitment of management and the Board of Directors to reducing financial leverage of the company through asset sales. I would also like to note we have protected a substantial portion of our projected operating cash flows in 2013 through downside hedge protection on approximately 85% of our projected oil production at an average price of $95.45 per barrel and approximately 50% of our projected natural gas production at an average price of $3.62 per mcf. This equates to approximately 72% of our projected 2013 natural gas, oil and NGL revenue, after differentials."

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2012 fourth quarter and compares them to results during the 2012 third quarter and the 2011 fourth quarter and also compares the 2012 full year to the 2011 full year.

	Three Months Ended			Full Year Ended	
	12/31/12	9/30/12	12/31/11	12/31/12	12/31/11
Average daily production (in mmcfe)	3,931	4,142	3,596	3,886	3,272
Natural gas equivalent production (in bcfe)	362	381	331	1,422	1,194
Natural gas equivalent realized price ($/mcfe)[a]	4.23	4.04	5.08	4.02	5.70
Oil production (in mbbls)	8,936	8,996	5,291	31,265	16,964
Average realized oil price ($/bbl)[a]	92.23	90.79	88.02	91.74	86.25
Oil as % of total production	15	14	10	13	9
NGL production (in mbbls)	4,634	4,130	4,476	17,615	14,712
Average realized NGL price ($/bbl)[a]	27.12	31.22	35.87	29.37	38.12
NGL as % of total production	8	7	8	7	7
Liquids as % of total realized revenue[b]	62	61	37	59	30
Liquids as % of unhedged revenue[b]	59	63	47	63	40
Natural gas production (in bcf)	280	302	272	1,129	1,004
Average realized natural gas price ($/mcf)[a]	2.07	1.97	3.87	2.07	4.77
Natural gas as % of total production	77	79	82	80	84
Natural gas as % of realized revenue	38	39	63	41	70
Natural gas as % of unhedged revenue	41	37	53	37	60
Marketing, gathering and compression net margin ($/mcfe)[c]	0.11	0.11	0.07	0.08	0.10
Oilfield services net margin ($/mcfe) [c][d]	0.05	0.09	0.09	0.10	0.10
Production expenses ($/mcfe)	(0.83)	(0.84)	(0.88)	(0.92)	(0.90)
Production taxes ($/mcfe)	(0.13)	(0.14)	(0.15)	(0.13)	(0.16)
General and administrative costs ($/mcfe)[e]	(0.23)	(0.33)	(0.35)	(0.33)	(0.38)
Stock-based compensation ($/mcfe)	(0.04)	(0.05)	(0.06)	(0.05)	(0.08)
DD&A of natural gas and liquids properties ($/mcfe)	(1.80)	(2.00)	(1.46)	(1.76)	(1.37)
D&A of other assets ($/mcfe)[f]	(0.20)	(0.17)	(0.26)	(0.21)	(0.24)
Interest expense ($/mcfe)[a]	(0.05)	(0.10)	(0.04)	(0.06)	(0.03)
Operating cash flow ($ in millions)[g]	1,146	1,118	1,311	4,069	5,309
Operating cash flow ($/mcfe)	3.17	2.93	3.96	2.86	4.45
Adjusted ebitda ($ in millions)[h]	1,089	1,021	1,308	3,754	5,406
Adjusted ebitda ($/mcfe)	3.01	2.68	3.95	2.64	4.53
Net income (loss) to common stockholders ($ in millions)	257	(2,055)	429	(940)	1,570
Earnings (loss) per share – diluted ($)	0.39	(3.19)	0.63	(1.46)	2.32
Adjusted net income to common stockholders ($ in millions)[i]	153	35	394	285	1,936
Adjusted earnings per share – diluted ($)	0.26	0.10	0.58	0.61	2.80

(a) Includes the effects of realized gains (losses) from hedging, but excludes the effects of unrealized gains (losses) from hedging.
(b) "Liquids" includes both oil and NGL.
(c) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
(d) 2012 fourth quarter and full year include impact of certain consolidated investments along with results from Chesapeake Oilfield Services.
(e) Excludes expenses associated with noncash stock-based compensation.
(f) The decrease from 2011 to 2012 (year over year and quarter over quarter) is due to assets being classified as held for sale as of June 30, 2012 and not subject to depreciation thereafter. The assets were sold as part of the midstream sale to ACMP in December 2012.
(g) Defined as cash flow provided by operating activities before changes in assets and liabilities.
(h) Defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on page 20.
(i) Defined as net income (loss) available to common stockholders, as adjusted to remove the effects of certain items detailed on page 21.

Hedging Positions Detailed

The following table summarizes Chesapeake's downside hedge position through swaps and collars on its 2013 natural gas and oil production as of February 20, 2013. The company does not currently have hedges in place for its NGL production. Depending on changes in natural gas and oil futures markets and management's view of underlying supply and demand trends, Chesapeake may increase or decrease some or all of its hedging positions at any time in the future without notice.

	Natural Gas		Oil	
Year	% of Forecasted Production	NYMEX Natural Gas	% of Forecasted Production	NYMEX Oil WTI
2013	50%	$3.62	85%	$95.45

Details of the company's year-end hedging positions will be provided in the company's Form 10-K filing with the Securities and Exchange Commission (SEC), and current positions are disclosed in summary format in management's Outlook dated February 21, 2013, which is attached to this release as Schedule "A," beginning on page 22. The Outlook has been updated from the Outlook dated November 1, 2012, attached as Schedule "B," which begins on page 25, to reflect various updated information.

2012 Fourth Quarter Average Daily Liquids Production Increases 39% Year over Year and 3% Sequentially to 147,500 Bbls; 2012 Fourth Quarter Average Daily Oil Production Increases 69% Year over Year and Was Flat Sequentially at 97,100 Bbls, Primarily as a Result of Asset Sales

Chesapeake's daily production for the 2012 fourth quarter averaged 3.931 bcfe, an increase of 9% from the average 3.596 bcfe produced per day in the 2011 fourth quarter and a decrease of 5% from the average 4.142 bcfe produced per day in the 2012 third quarter. The decrease was primarily the result of selling approximately 0.220 bcfe per day of production associated with the company's Permian Basin producing assets in September and October of 2012. Chesapeake's average daily production of 3.931 bcfe for the 2012 fourth quarter consisted of approximately 3.046 billion cubic feet (bcf) of natural gas (77% on a natural gas equivalent basis) and approximately 147,500 barrels (bbls) of liquids, consisting of approximately 97,100 bbls of oil (15% on a natural gas equivalent basis) and approximately 50,400 bbls of NGL (8% on a natural gas equivalent basis) (oil and NGL collectively referred to as "liquids").

For the 2012 fourth quarter, the company's year-over-year growth rate of natural gas production was 3%, or approximately 87 million cubic feet (mmcf) per day, and its year-over-year growth rate of liquids production was 39%, or approximately 41,300 bbls per day. Chesapeake's year-over-year liquids production growth consisted of oil production growth of 69%, or approximately 39,600 bbls per day, and NGL production growth of 4%, or approximately 1,700 bbls per day.

Chesapeake's daily production for the 2012 full year averaged 3.886 bcfe, a 19% increase from the average 3.272 bcfe produced per day for the 2011 full year. The company's average daily production of 3.886 bcfe for the 2012 full year consisted of approximately 3.084 bcf of natural gas (80% on a natural gas equivalent basis) and approximately 133,550 bbls of liquids, consisting of approximately 85,420 bbls of oil (13% on a natural gas equivalent basis) and approximately 48,130 bbls of NGL (7% on a natural gas equivalent basis).

For the 2012 full year, the company's year-over-year growth rate of natural gas production was 12%, or approximately 333 bcf per day, and its year-over-year growth rate of liquids production was 54%, or approximately 46,770 bbls per day. Chesapeake's year-over-year liquids production growth consisted of oil production growth of 84%, or approximately 38,950 bbls per day, and NGL production growth of 19%, or approximately 7,820 bbls per day.

As a result of completed and planned asset sales and the continued shift in focus in its drilling program from dry gas plays to liquids-rich plays, Chesapeake is projecting its natural gas production to decline approximately 7% in 2013 and is projecting its liquids production to increase approximately 27% in 2013.

During 2012, Company Adds New Net Proved Reserves of 5.0 Tcfe, or 840 Mmboe, through the Drillbit; Total Proved Reserves Decrease 17% to 15.7 Tcfe, or 2.6 Bboe, Primarily Due to Downward Price-Related Revisions and Net Divestitures

The company's December 31, 2012 estimated proved reserves were 15.690 tcfe, or 2.6 billion barrels of oil equivalent (bboe), a 17% decrease from year-end 2011. Chesapeake added 5.042 tcfe, or 840 million barrels of oil equivalent (mmboe), of new proved reserves (net of 1.349 tcfe, or 225 mmboe of nonprice-related revisions) through the drillbit at a drilling and completion cost of $1.82 per thousand cubic feet of natural gas equivalent (mcfe), or $10.92 per barrel of oil equivalent (boe), during 2012.

Primarily as a result of lower natural gas prices, the company recorded downward price-related revisions of 5.414 tcfe, or 902 mmboe, during 2012. These price revisions were seen primarily with the removal of proved undeveloped reserves (PUDs) in the company's Barnett and Haynesville shale plays. The majority of the downward nonprice-related revisions of 1.349 tcfe resulted from the continued execution of the company's strategy to shift its drilling focus from natural gas to liquids-rich areas and to drill in the "core of the core" of its acreage positions. As rigs were reallocated, PUDs were removed from various non-core areas resulting in downward revisions. Additionally, during 2012, Chesapeake recorded net divestitures of 1.305 tcfe, or 218 mmboe.

The following table presents Chesapeake's December 31, 2012 estimated proved reserves, estimated future net cash flows from proved reserves (discounted at an annual rate of 10% before income taxes (PV-10)) and proved developed percentage, each calculated based on the trailing 12-month average price required under SEC rules and the 10-year average NYMEX strip prices as of December 31, 2012. Additional information regarding the SEC case can be found on page 14.

Pricing Method	**Natural Gas Price ($/mcf)**	**Oil Price ($/bbl)**	**Proved Reserves (tcfe)**	**PV-10 (billions)**	**Proved Developed Percentage**
Trailing 12-month avg (SEC)[a]	$2.76	$94.84	15.7	$17.8	57%
12/31/12 avg NYMEX strip[b]	$4.85	$87.90	19.6	$27.9	55%

a) Reserve volumes estimated using SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices as of December 31, 2012. This pricing assumption yields estimated proved reserves for SEC reporting purposes.

b) Natural gas and oil volumes estimated under the 10-year average NYMEX strip reflect an alternative pricing scenario that illustrates the sensitivity of proved reserves to a different pricing assumption. Futures prices represent an unbiased consensus estimate by market participants about the likely prices to be received for future production. Management believes that 10-year average NYMEX strip prices provide a better indicator of the likely economic producibility of the company's proved reserves than the historical 12-month average price.

Operational Update; Eagle Ford Production Grows 266% Year Over Year and 20% Sequentially

Since 2000, Chesapeake has built a leading position in 10 of what it believes are the Top 15 unconventional plays in the U.S. – the Eagle Ford Shale in South Texas; the Marcellus Shale in Pennsylvania and West Virginia; the Utica Shale in Ohio, West Virginia and Pennsylvania; the Granite Wash, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in Oklahoma and the Texas Panhandle; the Haynesville/Bossier shales in western Louisiana and East Texas; the Barnett Shale in North Texas; and the Niobrara Shale in the Powder River Basin in Wyoming. These 10 plays represent Chesapeake's core assets and are the nearly exclusive focus of the company's planned future drilling efforts.

During the past four years, Chesapeake has substantially shifted its drilling and completion activity to liquids-rich plays in response to strong U.S. oil prices and relatively weak U.S. natural gas prices. During 2012, the company invested approximately 84% of its operated drilling and completion capital expenditures in liquids-rich plays and projects approximately 86% of such expenditures will be invested in liquids-rich plays in 2013.

The company continues to achieve strong operational results in its liquids-rich plays, as highlighted below:

Eagle Ford Shale (South Texas): Chesapeake continues to generate impressive liquids production growth rates from its 485,000 net acres of leasehold in the Eagle Ford Shale in South Texas. Net production during the 2012 fourth quarter averaged 62,500 boe per day (143,200 gross operated boe per day). This represents an increase of 266% year over year and 20% sequentially. Approximately 66% of total Eagle Ford production during the 2012 fourth quarter was oil, 15% was NGL and 19% was natural gas.

As of December 31, 2012, Chesapeake had 534 gross operated producing wells in the Eagle Ford, of which 405 reached first production in 2012, including 98 in the fourth quarter. The company is currently operating 17 rigs in the play, down from a peak of 34 rigs in April 2012, and plans to operate an average of 16 rigs in 2013. Spud-to-spud cycle times have declined dramatically in the Eagle Ford, from 26 days in the 2011 fourth quarter to only 18 days in the 2012 fourth quarter. Chesapeake plans to drill fewer Eagle Ford wells in 2013 than in 2012; however, the planned number of wells turned-to-sales will be roughly equal in both years. The company remains on pace to have substantially all of its core and Tier 1 Eagle Ford acreage held by production by the end of 2013.

Of the 98 wells that commenced first production in the 2012 fourth quarter, 90 wells (or 92%) had peak production rates of more than 500 boe per day, including 27 wells (or 28%) with peak rates of more than 1,000 boe per day.

Three notable wells completed by Chesapeake in the Eagle Ford during the 2012 fourth quarter are as follows:

- The *Hahn Dew 1H* in DeWitt County, TX achieved a peak rate of approximately 1,985 boe per day, which included 550 bbls of oil, 360 bbls of NGL and 6.4 mmcf of natural gas per day;
- The *Flat Creek Unit A Dim 2H* in Dimmit County, TX achieved a peak rate of approximately 1,470 boe per day, which included 1,210 bbls of oil, 160 bbls of NGL and 0.6 mmcf of natural gas per day; and
- The *JJ Henry IX M 1H* in McMullen County, TX achieved a peak rate of approximately 1,275 boe per day, which included 1,160 bbls of oil, 55 bbls of NGL and 0.4 mmcf of natural gas per day.

As part of its “core of the core” strategy, Chesapeake is currently pursuing the sale of a portion of its existing northern Eagle Ford Shale leasehold and producing assets which are outside its core development area.

Utica Shale (eastern Ohio, Pennsylvania, West Virginia): Chesapeake continues to focus on developing the core wet gas window of the Utica Shale in eastern Ohio, a play in which the company holds the industry’s largest position, approximately 1.0 million net acres of leasehold. As of December 31, 2012, Chesapeake has drilled a total of 184 wells in the Utica, which includes 45 producing wells, 47 additional wells waiting on pipeline connection and 92 wells in various stages of completion. Chesapeake is currently operating 14 rigs in the Utica and plans to average 14 operated rigs during 2013. Production growth from the Utica is expected to accelerate during 2013 when two new third-party natural gas processing complexes will enable the company to turn a large portion of its well inventory to sales.

Three notable wells completed by Chesapeake in the Utica during the 2012 fourth quarter are as follows:

- The *Houyouse 15-13-5 1H* in Carroll County, OH achieved a peak rate of approximately 1,730 boe per day, which included 525 bbls of oil, 305 bbls of NGL and 5.4 mmcf of natural gas per day;
- The *Cain South 16-12-4 8H* in Jefferson County, OH achieved a peak rate of approximately 1,540 boe per day, which included 425 bbls of NGL and 6.7 mmcf of natural gas per day; and
- The *Walters 30-12-5 8H* in Carroll County, OH achieved a peak rate of approximately 1,140 boe per day, which included 315 bbls of oil, 220 bbls of NGL and 3.6 mmcf of natural gas per day.

As of December 31, 2012, the company's remaining drilling and completion carry from Total E&P USA, Inc. was approximately $1.15 billion. Chesapeake anticipates using 100% of the remaining carry by year-end 2014, and the carry will pay for 60% of Chesapeake's drilling and completion costs during that time.

Marcellus Shale (Pennsylvania, West Virginia): With approximately 1.8 million net acres, Chesapeake is the industry's largest leasehold owner in the Marcellus Shale, which spans from northern West Virginia across much of Pennsylvania into southern New York.

During the 2012 fourth quarter, Chesapeake's average daily net production in the northern dry gas portion of the Marcellus was 645 million cubic feet of natural gas equivalent (mmcfe) per day (1,485 gross operated mmcfe per day), an increase of 135% year over year and 19% sequentially. Chesapeake has reduced its operated rig count to five rigs in the northern dry gas portion of the Marcellus and anticipates maintaining that level of activity for the remainder of 2013.

Three notable wells completed by Chesapeake in the northern dry gas portion of the Marcellus during the 2012 fourth quarter are as follows:

- The *Holtan 5H* in Susquehanna County, PA achieved a peak rate of 12.6 mmcf of natural gas per day;
- The *Lopatofsky 2H* in Wyoming County, PA achieved a peak rate of 11.4 mmcf of natural gas per day; and
- The *Messersmith S Bra 1H* in Bradford County, PA achieved a peak rate of 10.5 mmcf of natural gas per day.

During the 2012 fourth quarter, Chesapeake's average daily net production in the southern wet gas portion of the play was approximately 155 mmcfe per day (260 gross operated mmcfe per day). Management expects production from the southern Marcellus will remain relatively flat until the ATEX pipeline, which will carry processed ethane to the Gulf Coast, comes online in late 2013. Chesapeake is currently drilling with three operated rigs in the southern wet gas portion of the Marcellus and anticipates maintaining that level of activity for the remainder of 2013.

Three notable wells completed by Chesapeake in the southern wet gas portion of the Marcellus during the 2012 fourth quarter are as follows:

- The *Mark Hickman 5H* in Ohio County, WV achieved an initial test rate of approximately 1,195 boe per day, which included 290 bbls of oil, 305 bbls of NGL and 3.6 mmcf of natural gas per day;
- The *Esther Weeks 1H* in Ohio County, WV achieved an initial test rate of approximately 1,000 boe per day, which included 195 bbls of oil, 265 bbls of NGL and 3.3 mmcf of natural gas per day; and
- The *Michael Southworth 8H* in Marshall County, WV achieved an initial test rate of approximately 955 boe per day, which included 305 bbls of oil, 215 bbls of NGL and 2.6 mmcf of natural gas per day.

The company is in the process of selling various non-core Marcellus acreage.

Mississippi Lime (northern Oklahoma, southern Kansas): Chesapeake's approximate 2.1 million net acres of leasehold is the industry's largest position in the Mississippi Lime play in northern Oklahoma and southern Kansas. Production for the 2012 fourth quarter averaged approximately 32,500 boe per day (41,600 gross operated boe per day), up 208% year over year and 30% sequentially. Approximately 45% of total Mississippi Lime production during the 2012 fourth quarter was oil, 9% was NGL and 46% was natural gas. As of December 31, 2012, Chesapeake had 273 producing wells in the Mississippi Lime play, which included 55 wells that reached first production in the 2012 fourth quarter, compared to 73 in the 2012 third quarter and 49 in the 2012 second quarter. Also, as of December 31, 2012, Chesapeake had approximately 46 wells drilled, but not yet producing, that were in various stages of completion and/or waiting on pipeline connection. Chesapeake is currently operating eight rigs in the Mississippi Lime and anticipates maintaining that level of activity for the remainder of 2013.

Three notable wells completed by Chesapeake in the Mississippi Lime during the 2012 fourth quarter are as follows:

- The *Mike 2-28-15 1H* in Woods County, OK achieved a peak rate of approximately 2,820 boe per day, which included 2,345 bbls of oil, 100 bbls of NGL and 2.3 mmcf of natural gas per day;
- The *Roper 1-28-15 1H* in Woods County, OK achieved a peak rate of approximately 1,985 boe per day, which included 1,645 bbls of oil, 70 bbls of NGL and 1.6 mmcf of natural gas per day; and
- The *Thorp 4-24-10 1H* in Alfalfa County, OK achieved a peak rate of approximately 1,365 boe per day, which included 465 bbls of oil, 215 bbls of NGL and 4.1 mmcf of natural gas per day.

2012 Fourth Quarter and Full Year Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled for Thursday, February 21, 2013 at 9:00 am EST. The telephone number to access the conference call is **913-981-5550** or toll-free **800-289-0508**. The passcode for the call is **8878841**. We encourage those who would like to participate in the call to place calls between 8:50 and 9:00 am EST. For those unable to participate in the conference call, a replay will be available for audio playback at 1:00 pm EST on Thursday, February 21, 2013 and will run through midnight Thursday, March 7, 2013. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **8878841**. The conference call will also be webcast live on Chesapeake's website at www.chk.com in the "Events" subsection of the "Investors" section of the company's website. The webcast of the conference will be available on the company's website for one year.

This news 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 are statements other than statements of historical fact that give our current expectations or forecasts of future events. They include estimates of natural gas and liquids reserves, projected production, estimates of operating costs, planned development drilling and use of joint venture drilling carries, anticipated asset sales, projected cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the estimated contribution of derivative contracts 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 news release, and we undertake no obligation to update this information.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2011 annual report on Form 10-K filed with the U.S. Securities and Exchange Commission on February 29, 2012. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including through planned asset sales, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures; inability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas and oil sales; the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; general economic conditions negatively impacting us and our business counterparties; oilfield services shortages and transportation capacity constraints and interruptions that could adversely affect our cash flow; and losses possible from pending or future litigation and regulatory investigations. We do not have binding agreements for all of our planned 2013 asset sales. Our ability to consummate each of these transactions is subject to changes in market conditions and other factors. If one or more of the transactions is not completed in the anticipated time frame or at all or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness as planned could be adversely affected.

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.

Chesapeake Energy Corporation (NYSE:CHK) is the second-largest producer of natural gas, a Top 11 producer of oil and natural gas liquids and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Eagle Ford, Utica, Granite Wash, Cleveland, Tonkawa, Mississippi Lime and Niobrara unconventional liquids plays and in the Marcellus, Haynesville/Bossier and Barnett unconventional natural gas shale plays. The company has also vertically integrated its operations and owns substantial marketing and oilfield services businesses through its subsidiaries Chesapeake Energy Marketing, Inc. and Chesapeake Oilfield Operating, L.L.C. Further information is available at www.chk.com where Chesapeake routinely posts announcements, updates, events, investor information, presentations and news releases.

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in millions, except per-share and unit data)
(unaudited)

THREE MONTHS ENDED:	December 31, 2012		December 31, 2011	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas, oil and NGL	1,657	4.58	1,336	4.03
Marketing, gathering and compression	1,721	4.76	1,246	3.77
Oilfield services	161	0.45	145	0.44
Total Revenues	3,539	9.79	2,727	8.24
OPERATING EXPENSES:				
Natural gas, oil and NGL production	299	0.83	292	0.88
Production taxes	47	0.13	51	0.15
Marketing, gathering and compression	1,681	4.65	1,223	3.70
Oilfield services	145	0.40	115	0.35
General and administrative	99	0.27	138	0.42
Employee retirement expense and other termination benefits	3	0.01	—	—
Natural gas, oil and NGL depreciation, depletion and amortization	651	1.80	484	1.46
Depreciation and amortization of other assets	71	0.20	85	0.26
Net gains on sales of fixed assets	(272)	(0.75)	(439)	(1.33)
Impairments of fixed assets and other	59	0.16	42	0.13
Total Operating Expenses	2,783	7.70	1,991	6.02
INCOME (LOSS) FROM OPERATIONS	756	2.09	736	2.22
OTHER INCOME (EXPENSE):				
Interest expense	(14)	(0.04)	(7)	(0.02)
Earnings (losses) on investments	(16)	(0.04)	56	0.17
Gain on sale of investment	31	0.09	—	—
Losses on purchases of debt	(200)	(0.55)	—	—
Other income	6	0.01	14	0.04
Total Other Income (Expense)	(193)	(0.53)	63	0.19
INCOME (LOSS) BEFORE INCOME TAXES	563	1.56	799	2.41
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	23	0.06	2	—
Deferred income taxes	196	0.55	310	0.94
Total Income Tax Expense (Benefit)	219	0.61	312	0.94
NET INCOME (LOSS)	344	0.95	487	1.47
Net income attributable to noncontrolling interests	(44)	(0.12)	(15)	(0.04)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	300	0.83	472	1.43
Preferred stock dividends	(43)	(0.12)	(43)	(0.13)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	257	0.71	429	1.30
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.39		$ 0.67	
Diluted	$ 0.39		$ 0.63	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	644		640	
Diluted	648		750	

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in millions, except per-share and unit data)
(unaudited)

TWELVE MONTHS ENDED:	December 31, 2012		December 31, 2011	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas, oil and NGL	6,278	4.42	6,024	5.04
Marketing, gathering and compression	5,431	3.81	5,090	4.26
Oilfield services	607	0.43	521	0.44
Total Revenues	12,316	8.66	11,635	9.74
OPERATING EXPENSES:				
Natural gas, oil and NGL production	1,304	0.92	1,073	0.90
Production taxes	188	0.13	192	0.16
Marketing, gathering and compression	5,312	3.73	4,967	4.16
Oilfield services	465	0.33	402	0.34
General and administrative	535	0.38	548	0.46
Employee retirement expense and other termination benefits	7	0.01	—	—
Natural gas, oil and NGL depreciation, depletion and amortization	2,507	1.76	1,632	1.37
Depreciation and amortization of other assets	304	0.21	291	0.24
Impairment of natural gas and oil properties	3,315	2.33	—	—
Net gains on sales of fixed assets	(267)	(0.18)	(437)	(0.37)
Impairments of fixed assets and other	340	0.24	46	0.03
Total Operating Expenses	14,010	9.86	8,714	7.29
INCOME (LOSS) FROM OPERATIONS	(1,694)	(1.20)	2,921	2.45
OTHER INCOME (EXPENSE):				
Interest expense	(77)	(0.05)	(44)	(0.04)
Earnings (losses) on investments	(103)	(0.08)	156	0.13
Gain on sales of investments	1,092	0.77	—	—
Losses on purchases of debt	(200)	(0.14)	(176)	(0.15)
Other income	8	0.01	23	0.02
Total Other Income (Expense)	720	0.51	(41)	(0.04)
INCOME (LOSS) BEFORE INCOME TAXES	(974)	(0.69)	2,880	2.41
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	47	0.03	13	0.01
Deferred income taxes	(427)	(0.30)	1,110	0.93
Total Income Tax Expense (Benefit)	(380)	(0.27)	1,123	0.94
NET INCOME (LOSS)	(594)	(0.42)	1,757	1.47
Net income attributable to noncontrolling interests	(175)	(0.12)	(15)	(0.01)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(769)	(0.54)	1,742	1.46
Preferred stock dividends	(171)	(0.12)	(172)	(0.15)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	(940)	(0.66)	1,570	1.31
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (1.46)		$ 2.47	
Diluted	$ (1.46)		$ 2.32	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	643		637	
Diluted	643		752	

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
($ in millions)
(unaudited)

	December 31, 2012	December 31, 2011
Cash and cash equivalents	$ 287	$ 351
Other current assets	2,661	2,826
Total Current Assets	2,948	3,177
Property and equipment (net)	37,167	36,739
Other assets	1,496	1,919
Total Assets	$ 41,611	$ 41,835
Current liabilities	$ 6,266	$ 7,082
Long-term debt, net of discounts	12,157	10,626
Other long-term liabilities	2,485	2,682
Deferred income tax liabilities	2,807	3,484
Total Liabilities	23,715	23,874
Chesapeake stockholders' equity	15,569	16,624
Noncontrolling interests	2,327	1,337
Total Equity	17,896	17,961
Total Liabilities and Equity	$ 41,611	$ 41,835
Common Shares Outstanding (in millions)	664	659

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION
($ in millions)
(unaudited)

	December 31, 2012	December 31, 2011
Total debt, net of unrestricted cash	$ 12,333	$ 10,275
Chesapeake stockholders' equity	15,569	16,624
Noncontrolling interests[(a)]	2,327	1,337
Total	$ 30,229	$ 28,236
Debt to capitalization ratio	41%	36%

	December 31, 2012	December 31, 2011
(a) Includes third-party ownership as follows:		
CHK Cleveland Tonkawa, L.L.C.	$ 1,015	$ —
CHK Utica, L.L.C.	950	950
Chesapeake Granite Wash Trust	356	380
Other	6	7
Total	$ 2,327	$ 1,337

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2012 CHANGES TO NATURAL GAS AND OIL PROPERTIES
BASED ON SEC PRICING OF TRAILING 12-MONTH AVERAGE PRICES AS OF DECEMBER 31, 2012
($ in millions, except per-unit data)
(unaudited)

	Proved Reserves		
	Cost	Bcfe[(a)]	$/Mcfe
PROVED PROPERTIES:			
Well costs on proved properties[(b)(c)]	$ 9,168	5,042[(d)]	1.82
Acquisition of proved properties[(e)]	332	42	7.91
Sale of proved properties	(2,462)	(1,347)	1.83
Total net proved properties	7,038	3,737	1.88
Revisions – price	—	(5,414)	—
UNPROVED PROPERTIES:			
Well costs on unproved properties[(f)]	(337)	—	—
Acquisition of unproved properties, net[(g)]	1,718	—	—
Acquisition of minerals	68	—	—
Sale of unproved properties	(3,146)	—	—
Total net unproved properties	(1,697)	—	—
OTHER:			
Capitalized interest on unproved properties	976	—	—
Geological and geophysical costs	170	—	—
Asset retirement obligations	32	—	—
Total other	1,178	—	—
Total	$ 6,519	(1,677)	—

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
TWELVE MONTHS ENDED DECEMBER 31, 2012
BASED ON SEC PRICING OF TRAILING 12-MONTH AVERAGE PRICES AS OF DECEMBER 31, 2012
(unaudited)

	Bcfe[(a)]
Beginning balance, January 1, 2012	18,789
Production	(1,422)
Acquisitions	42
Divestitures	(1,347)
Revisions – changes to previous estimates	(1,349)
Revisions – price	(5,414)
Extensions and discoveries	6,391
Ending balance, December 31, 2012	15,690
Proved reserves decline rate before acquisitions and divestitures	10%
Proved reserves decline rate after acquisitions and divestitures	17%
Proved developed reserves	8,944
Proved developed reserves percentage	57%
PV-10 ($ in billions)[(a)]	$ 17.8

(a) Reserve volumes and PV-10 value estimated using SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices as of December 31, 2012 of $2.76 per mcf of natural gas and $94.84 per bbl of oil, before field differential adjustments.

(b) Net of well cost carries of $784 million associated with the Statoil-Marcellus, CNOOC-Eagle Ford, CNOOC-Niobrara and Total-Utica joint ventures.

(c) Includes $1.389 billion of well costs incurred in prior quarters (previously classified as well costs on unproved properties) related to wells that were evaluated for the existence of proved reserves in the current quarter.

(d) Includes 1.349 tcfe of downward revisions resulting from changes to previous estimates and excludes downward revisions of 5.414 tcfe primarily resulting from lower natural gas prices using the average first-day-of-the-month price for the twelve months ended December 31, 2012, compared to the twelve months ended December 31, 2011.

(e) Includes 28 bcfe of proved reserves associated with the company's Permian Basin volumetric production payment repurchased by the company for $313 million and subsequently resold to multiple parties in September and October 2012.

(f) Includes $1.052 million of well costs on unproved properties incurred in the current year, offset by the transfer of $1.389 billion previously classified as well costs on unproved properties that were evaluated for the existence of proved reserves in the current quarter. See footnote (c).

(g) Net of joint venture partner reimbursements.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF PV-10
($ in millions)
(unaudited)

	December 31, 2012	December 31, 2011
Standardized measure of discounted future net cash flows	$ 14,666	$ 15,630
Discounted future cash flows for income taxes	3,107	4,247
Discounted future net cash flows before income taxes (PV-10)	$ 17,773	$ 19,877

PV-10 is discounted (at 10% per year) future net cash flows before income taxes. The standardized measure of discounted future net cash flows includes the effects of estimated future income tax expenses and is calculated in accordance with Accounting Standards Topic 932. Management uses PV-10 as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. The company also understands that securities analysts and rating agencies use this measure in similar ways. While PV-10 is based on prices, costs and discount factors which are consistent from company to company, the standardized measure is dependent on the unique tax situation of each individual company.

The company's PV-10 and standardized measure were calculated using trailing 12-month average first-day-of-the-month prices. As of December 31, 2012 and 2011, the prices used were $2.76 per mcf and $94.84 per bbl and $4.12 per mcf and $95.97 per bbl, respectively, before field differential adjustments.

CHESAPEAKE ENERGY CORPORATION
SUPPLEMENTAL DATA – NATURAL GAS, OIL AND NGL SALES AND INTEREST EXPENSE
(unaudited)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	**2011**	**2012**	**2011**
Natural Gas, Oil and NGL Sales ($ in millions):				
Natural gas sales	$ 645	$ 720	$ 2,004	$ 3,133
Natural gas derivatives – realized gains (losses)	(63)	335	328	1,656
Natural gas derivatives – unrealized gains (losses)	70	24	(331)	(669)
Total Natural Gas Sales	652	1,079	2,001	4,120
Oil sales	790	475	2,829	1,523
Oil derivatives – realized gains (losses)	34	(10)	39	(60)
Oil derivatives – unrealized gains (losses)	54	(375)	857	(128)
Total Oil Sales	878	90	3,725	1,335
NGL sales	126	171	526	603
NGL derivatives – realized gains (losses)	—	(10)	(9)	(42)
NGL derivatives – unrealized gains (losses)	1	6	35	8
Total NGL Sales	127	167	552	569
Total Natural Gas, Oil and NGL Sales	$ 1,657	$ 1,336	$ 6,278	$ 6,024
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 2.30	$ 2.64	$ 1.77	$ 3.12
Oil ($ per bbl)	$ 88.44	$ 89.85	$ 90.49	$ 89.80
NGL ($ per bbl)	$ 27.20	$ 38.19	$ 29.89	$ 40.96
Natural gas equivalent ($ per mcfe)	$ 4.32	$ 4.13	$ 3.77	$ 4.40
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 2.07	$ 3.87	$ 2.07	$ 4.77
Oil ($ per bbl)	$ 92.23	$ 88.02	$ 91.74	$ 86.25
NGL ($ per bbl)	$ 27.12	$ 35.87	$ 29.37	$ 38.12
Natural gas equivalent ($ per mcfe)	$ 4.23	$ 5.08	$ 4.02	$ 5.70
Interest Expense (Income) ($ in millions):				
Interest[(a)]	$ 17	$ 11	$ 84	$ 30
Derivatives – realized (gains) losses	—	1	(1)	7
Derivatives – unrealized (gains) losses	(3)	(5)	(6)	7
Total Interest Expense	$ 14	$ 7	$ 77	$ 44

(a) Net of amounts capitalized.

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED CASH FLOW DATA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	December 31, 2012	December 31, 2011
Beginning cash	$ 142	$ 111
Cash provided by operating activities	864	2,179
Cash flows from investing activities:		
Well costs on proved and unproved properties	(1,377)	(2,080)
Acquisition of proved and unproved properties[(a)]	(295)	(1,163)
Sale of proved and unproved properties	3,386	1,257
Geological and geophysical costs	(28)	(42)
Additions to other property and equipment	(719)	(593)
Proceeds from sales of other assets	2,273	630
Additions to investments	(145)	(25)
Other	79	(81)
Total cash provided by (used in) investing activities	3,174	(2,097)
Cash provided by (used in) financing activities	(3,907)	158
Change in cash and cash equivalents classified in current assets held for sale	14	—
Ending cash	$ 287	$ 351

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
Beginning cash	$ 351	$ 102
Cash provided by operating activities	2,841	5,903
Cash flows from investing activities:		
Well costs on proved and unproved properties	(8,737)	(7,257)
Acquisition of proved and unproved properties[(b)]	(2,890)	(4,463)
Sale of proved and unproved properties	5,613	7,140
Geological and geophysical costs	(193)	(210)
Additions to other property and equipment	(2,635)	(2,009)
Proceeds from sales of other assets	2,492	1,312
Acquisition of drilling company	—	(339)
Proceeds from (additions to) investments	(406)	101
Proceeds from sale of midstream investment	2,000	—
Other	(224)	(87)
Total cash used in investing activities	(4,980)	(5,812)
Cash provided by financing activities	2,075	158
Ending cash	$ 287	$ 351

(a) Includes capitalized interest of $153 million and $152 million for the current quarter and the prior quarter, respectively.
(b) Includes capitalized interest of $776 million and $630 million for the current period and the prior period, respectively.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 864	$ 949	$ 2,179
Changes in assets and liabilities	282	169	(868)
OPERATING CASH FLOW[(a)]	$ 1,146	$ 1,118	$ 1,311

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
NET INCOME (LOSS)	$ 344	$ (1,971)	$ 487
Income tax expense (benefit)	219	(1,260)	312
Interest expense	14	36	7
Depreciation and amortization of other assets	71	66	85
Natural gas, oil and NGL depreciation, depletion and amortization	651	762	484
EBITDA[(b)]	$ 1,299	$ (2,367)	$ 1,375

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 864	$ 949	$ 2,179
Changes in assets and liabilities	282	169	(868)
Interest expense	14	36	7
Unrealized gains (losses) on natural gas, oil and NGL derivatives	125	(104)	(345)
Impairment of natural gas and oil properties	—	(3,315)	—
Net gains (losses) on sales of fixed assets	272	(7)	439
Impairments of fixed assets and other	(59)	(14)	(42)
Gains (losses) on investments	(2)	4	22
Stock-based compensation	(27)	(30)	(34)
Losses on purchases of debt	(200)	—	—
Other items	30	(55)	17
EBITDA[(b)]	$ 1,299	$ (2,367)	$ 1,375

(a) 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 a natural gas and oil 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 natural gas and oil 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.

(b) Ebitda represents net income (loss) 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 agreements and is used in the financial covenants in our bank credit agreements. 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.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,841	$ 5,903
Changes in assets and liabilities	1,228	(594)
OPERATING CASH FLOW[a]	$ 4,069	$ 5,309

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
NET INCOME (LOSS)	$ (594)	$ 1,757
Income tax expense (benefit)	(380)	1,123
Interest expense	77	44
Depreciation and amortization of other assets	304	291
Natural gas, oil and NGL depreciation, depletion and amortization	2,507	1,632
EBITDA[b]	$ 1,914	$ 4,847

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,841	$ 5,903
Changes in assets and liabilities	1,228	(594)
Interest expense	77	44
Unrealized gains (losses) on natural gas, oil and NGL derivatives	561	(789)
Impairment of natural gas and oil properties	(3,315)	—
Net gains on sales of fixed assets	267	437
Impairments of fixed assets and other	(316)	(46)
Gains (losses) on investments	(180)	41
Stock-based compensation	(120)	(153)
Gains on sales of investments	1,092	—
Losses on purchases of debt	(200)	(5)
Other items	(21)	9
EBITDA[b]	$ 1,914	$ 4,847

(a) 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 a natural gas and oil 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 natural gas and oil 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.

(b) Ebitda represents net income (loss) 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 agreements and is used in the financial covenants in our bank credit agreements. 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.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EBITDA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
EBITDA	$ 1,299	$ (2,367)	$ 1,375
Adjustments:			
Unrealized (gains) losses on natural gas, oil and NGL derivatives	(125)	104	345
Impairment of natural gas and oil properties	—	3,315	—
Net (gains) losses on sales of fixed assets	(272)	7	(439)
Impairments of fixed assets and other	59	38	42
Net income attributable to noncontrolling interests	(44)	(41)	(15)
Gains on sales of investments	(31)	(31)	—
Losses on purchases of debt	200	—	—
Other	3	(4)	—
Adjusted EBITDA[(a)]	$ 1,089	$ 1,021	$ 1,308

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
EBITDA	$ 1,914	$ 4,847
Adjustments:		
Unrealized (gains) losses on natural gas, oil and NGL derivatives	(561)	789
Impairment of natural gas and oil properties	3,315	—
Net gains on sales of fixed assets	(267)	(437)
Impairments of fixed assets and other	340	46
Net income attributable to noncontrolling interests	(175)	(15)
Losses on purchases of debt	200	176
(Gains) on investments	(1,019)	—
Other	7	—
Adjusted EBITDA[(a)]	$ 3,754	$ 5,406

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

(i) Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.

(ii) Adjusted ebitda is more comparable to estimates provided by securities analysts.

(iii) 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 STOCKHOLDERS
($ in millions, except per-share data)
(unaudited)

THREE MONTHS ENDED:	December 31, 2012	September 30, 2012	December 31, 2011
Net income (loss) available to common stockholders	$ 257	$ (2,055)	$ 429
Adjustments, net of tax:			
Unrealized (gains) losses on derivatives	(78)	63	207
Impairment of natural gas and oil properties	—	2,022	—
Net (gains) losses on sales of fixed assets	(166)	4	(268)
Impairments of fixed assets and other	36	23	26
Gains on sales of investments	(19)	(19)	—
Losses on purchases or exchanges of debt	122	—	—
Other	1	(3)	—
Adjusted net income available to common stockholders[a]	153	35	394
Preferred stock dividends	43	43	43
Total adjusted net income	$ 196	$ 78	$ 437
Weighted average fully diluted shares outstanding[b]	754	754	750
Adjusted earnings per share assuming dilution[a]	$ 0.26	$ 0.10	$ 0.58

TWELVE MONTHS ENDED:	December 31, 2012	December 31, 2011
Net income (loss) available to common stockholders	$ (940)	$ 1,570
Adjustments, net of tax:		
Unrealized (gains) losses on derivatives	(347)	486
Impairment of natural gas and oil properties	2,022	—
Net gains on sales of fixed assets	(163)	(266)
Impairments of fixed assets and other	208	28
Losses on purchases or exchanges of debt	122	107
Loss on foreign currency derivatives	—	11
Gains on investments	(622)	—
Other	5	—
Adjusted net income available to common stockholders[a]	285	1,936
Preferred stock dividends	171	172
Total adjusted net income	$ 456	$ 2,108
Weighted average fully diluted shares outstanding[b]	755	752
Adjusted earnings per share assuming dilution[a]	$ 0.61	$ 2.80

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

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

(ii) Adjusted net income available to common stockholders is more comparable to earnings estimates provided by securities analysts.

(iii) 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.

(b) Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

SCHEDULE "A"
MANAGEMENT'S OUTLOOK AS OF FEBRUARY 21, 2013

Chesapeake periodically provides management guidance on certain factors that affect its future financial performance. The primary changes from the company's November 1, 2012 Outlook are in ***italicized bold*** and reflect estimated future production decreases of approximately 35 bcfe in 2013 associated with the company's planned asset sales.

Chesapeake Energy Corporation Consolidated Projections

	Year Ending 12/31/13
Estimated Production:	
Natural gas – bcf	1,030 – 1,070
Oil – mbbls	36,000 – 38,000
NGL – mbbls[(a)]	24,000 – 26,000
Natural gas equivalent – bcfe	1,390 – 1,454
Daily natural gas equivalent midpoint – mmcfe	3,895
YOY estimated production increase (adjusted for planned asset sales)	***0%***
NYMEX Price[(b)] (for calculation of realized hedging effects only):	
Natural gas - $/mcf	***$3.67***
Oil - $/bbl	***$95.00***
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):	
Natural gas - $/mcf	***($0.05)***
Oil - $/bbl	***$0.30***
Estimated Gathering/Marketing/Transportation Differentials to NYMEX Prices:	
Natural gas - $/mcf	$1.15 – 1.25
Oil - $/bbl	***$0.00 – 2.00***
NGL - $/bbl	***$66.00 – 70.00***
Operating Costs per Mcfe of Projected Production:	
Production expense	$0.90 ***– 0.95***
Production taxes	***$0.20 – 0.25***
General and administrative[(c)]	***$0.34 – 0.39***
Stock-based compensation (noncash)	$0.04 – 0.06
DD&A of natural gas and liquids assets	$1.65 – 1.85
Depreciation of other assets	$0.25 – 0.30
Interest expense[(d)]	$0.05 – 0.10
Other ($ millions):	
Marketing, gathering and compression net margin[(e)]	***$90 – 100***
Oilfield services net margin[(e)]	***$175 – 225***
Net income attributable to noncontrolling interests and other[(f)]	***($180) – (220)***
Book Tax Rate	39%
Weighted average shares outstanding (in millions):	
Basic	645 – 650
Diluted	758 – 763
Operating cash flow before changes in assets and liabilities[(g)(h)]	***$4,850 – 5,150***
Well costs on proved and unproved properties	($5,750 – 6,250)
Acquisition of unproved properties, net	($400)

a) Assumes no ethane rejection.
b) NYMEX natural gas and oil prices have been updated for actual contract prices through February and January, respectively.
c) Excludes expenses associated with noncash stock-based compensation.
d) Does not include unrealized gains or losses on interest rate derivatives.
e) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
f) Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust, CHK Utica, L.L.C. and CHK Cleveland Tonkawa, L.L.C.
g) A non-GAAP financial measure. We are unable to provide a reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities.
h) Assumes NYMEX prices on open contracts of $3.50 to $4.00 per mcf and $95.00 per bbl in 2013.

Natural Gas, Oil and NGL Hedging Activities

Chesapeake enters into natural gas, oil and NGL derivative transactions in order to mitigate a portion of its exposure to adverse changes in market prices. Please see the quarterly reports on Form 10-Q and annual reports on Form 10-K filed by Chesapeake with the SEC for detailed information about derivative instruments the company uses, its quarter-end derivative positions and the accounting for natural gas, oil and NGL derivatives.

As of February 21, 2013, the company has the following open natural gas swaps in place and gains (losses) related to closed natural gas trades and premiums for call options for future production periods.

	Open Swaps (bcf)	Avg. NYMEX Price of Open Swaps	Forecasted Natural Gas Production (bcf)	Open Swap Positions as a % of Forecasted Natural Gas Production	Total Gains (Losses) from Closed Trades and Premiums for Call Options ($ in millions)	Total Gains (Losses) from Closed Trades and Premiums for Call Options per mcf of Forecasted Natural Gas Production
Q1 2013	***53***	***$ 3.72***			***$ (9)***	
Q2 2013	***137***	***3.66***			***11***	
Q3 2013	***141***	***3.59***			***7***	
Q4 2013	***141***	***3.59***			***(3)***	
Total 2013	***472***	***$ 3.63***	1,050	***45%***	***$ 6***	$ 0.00
Total 2014	0	-			$ (74)	
Total 2015	0	-			$ (131)	
Total 2016 – 2022	0	-			***$ (187)***	

The company currently has the following purchased natural gas three-way collars in place:

	Open Collars (bcf)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Ceiling Price	Forecasted Natural Gas Production (bcf)	Open Collars as a % of Forecasted Natural Gas Production
Q1 2013	***0***	***$ -***	***$ -***	***$ -***		
Q2 2013	***18***	***3.03***	***3.55***	***4.03***		
Q3 2013	***18***	***3.03***	***3.55***	***4.03***		
Q4 2013	***18***	***3.03***	***3.55***	***4.03***		
Total 2013	***54***	***$ 3.03***	***$ 3.55***	***$ 4.03***	1,050	***5%***

The company currently has the following natural gas written call options in place:

	Call Options (bcf)	Avg. NYMEX Strike Price	Forecasted Natural Gas Production (bcf)	Call Options as a % of Forecasted Natural Gas Production
Q1 2013	0	$ -		
Q2 2013	0	-		
Q3 2013	0	-		
Q4 2013	0	-		
Total 2013	0	$ -	1,050	0%
Total 2014	0	$ -		
Total 2015	0	$ -		
Total 2016 – 2020	***193***	***$ 9.92***		

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

	Volume (bcf)	Avg. NYMEX less
Q1 2013	11	$ 0.21
Q2 2013	11	0.21
Q3 2013	11	0.21
Q4 2013	11	0.21
Total 2013	44	$ 0.21
Total 2014	28	$ 0.32
Total 2015	***31***	***$ 0.34***
Total 2016-2022	***8***	***$ 1.02***

As of February 21, 2013, the company has the following open crude oil swaps in place and gains (losses) related to closed crude oil contracts and premiums for call options for future production:

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps	Forecasted Oil Production (mbbls)	Open Swap Positions as a % of Forecasted Oil Production	Total Gains (Losses) from Closed Trades and Premiums for Call Options ($ in millions)	Total Gains (Losses) from Closed Trades and Premiums for Call Options per bbl of Forecasted Oil Production
Q1 2013	***6,401***	***$ 95.52***			$ 1	
Q2 2013	***7,935***	***95.56***			1	
Q3 2013	***8,451***	***95.42***			2	
Q4 2013	***8,796***	***95.33***			2	
Total 2013	***31,583***	***$ 95.45***	37,000	***85%***	$ 6	$ 0.17
Total 2014	***18,073***	***$ 93.67***			$ (151)	
Total 2015	500	$ 88.75			$ 265	
Total 2016 – 2022	0	$ -			$ 117	

The company currently has the following crude oil written call options in place:

	Call Options (mbbls)	Avg. NYMEX Strike Price	Forecasted Oil Production (mbbls)	Call Options as a % of Forecasted Oil Production
Q1 2013	***2,125***	***$ 98.09***		
Q2 2013	***1,954***	***97.90***		
Q3 2013	***1,975***	***97.90***		
Q4 2013	***1,975***	***97.90***		
Total 2013	***8,029***	***$ 97.95***	37,000	***22%***
Total 2014	17,612	$ 98.79		
Total 2015	27,048	$ 100.99		
Total 2016 – 2017	24,220	$ 100.07		

The company has the following oil basis protection swaps in place:

	Volume (mbbls)	Avg. NYMEX plus
Q1 2013	***2,340***	***$ 15.09***
Q2 2013	***2,457***	***12.34***
Q3 2013	***736***	***10.07***
Q4 2013	***0***	***-***
Total 2013	***5,533***	***$ 13.20***

SCHEDULE "B"
MANAGEMENT'S OUTLOOK AS OF NOVEMBER 1, 2012
(PROVIDED FOR REFERENCE ONLY)
NOW SUPERSEDED BY OUTLOOK AS OF FEBRUARY 21, 2013

Chesapeake periodically provides management guidance on certain factors that affect its future financial performance. The primary changes from the company's August 6, 2012 Outlook reflect estimated natural gas curtailments of approximately 60 bcf in the 2012 first half and also include estimated future production decreases of approximately 45 bcfe in 2012 and 140 bcfe in 2013 associated with the company's completed and planned asset sales. Management and the board of directors continue to review operational plans for 2013 and beyond which could result in changes to this Outlook.

Chesapeake Energy Corporation Consolidated Projections
For Years Ending December 31, 2012 and 2013

	Year Ending 12/31/12	Year Ending 12/31/13
Estimated Production:		
Natural gas – bcf	1,120 – 1,140	1,030 – 1,070
Oil – mbbls	30,000 – 31,000	36,000 – 38,000
NGL – mbbls	17,000 – 18,000	24,000 – 26,000
Natural gas equivalent – bcfe	1,402 – 1,434	1,390 – 1,454
Daily natural gas equivalent midpoint – mmcfe	3,870	3,895
YOY estimated production increase (adjusted for planned asset sales)	18%	1%
NYMEX Price[a] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	$2.77	$4.00
Oil - $/bbl	$94.66	$90.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	$0.30	$0.00
Oil - $/bbl	$0.99	$4.50
Estimated Gathering/Marketing/Transportation Differentials to NYMEX Prices:		
Natural gas - $/mcf	$1.00 –1.10	$1.15 – 1.25
Oil - $/bbl	$4.50 – 6.50	$4.50 – 6.50
NGL - $/bbl	$67.00 – 70.00	$63.00 – 67.00
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.90 – 1.00	$0.90 – 1.00
Production taxes (~5% of O&G revenues)	$0.15 – 0.20	$0.25 – 0.30
General and administrative[b]	$0.39 – 0.44	$0.39 – 0.44
Stock-based compensation (noncash)	$0.04 – 0.06	$0.04 – 0.06
DD&A of natural gas and liquids assets	$1.65 – 1.85	$1.65 – 1.85
Depreciation of other assets	$0.22 – 0.27	$0.25 – 0.30
Interest expense[c]	$0.05 – 0.10	$0.05 – 0.10
Other ($ millions):		
Marketing, gathering and compression net margin[d]	$90 – 100	$50 – 75
Oilfield services net margin[d]	$175 – 200	$200 – 250
Other income (including certain equity investments)	$25	–
Net income attributable to noncontrolling interest[e]	($180) – (200)	($200) – (240)
Book Tax Rate	39%	39%
Weighted average shares outstanding (in millions):		
Basic	640 – 645	645 – 650
Diluted	753 – 758	758 – 763
Operating cash flow before changes in assets and liabilities[f][g]	$3,800	$4,250 – 5,250
Well costs on proved and unproved properties	($8,750)	($5,750 – 6,250)
Acquisition of unproved properties, net	($1,750)	($400)

a) NYMEX natural gas and oil prices have been updated for actual contract prices through October and September, respectively.
b) Excludes expenses associated with noncash stock-based compensation.
c) Does not include unrealized gains or losses on interest rate derivatives.
d) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
e) Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust, CHK Utica, L.L.C., CHK Cleveland Tonkawa, L.L.C. and Cardinal Gas Services, L.L.C.
f) A non-GAAP financial measure. We are unable to provide a reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities.
g) Assumes NYMEX prices on open contracts of $3.50 per mcf and $90.00 per bbl in 2012 and $3.50 to $4.50 per mcf and $90.00 per bbl in 2013.

Natural Gas, Oil and NGL Hedging Activities

Chesapeake enters into natural gas, oil and NGL derivative transactions in order to mitigate a portion of its exposure to adverse changes in market prices. Please see the quarterly reports on Form 10-Q and annual reports on Form 10-K filed by Chesapeake with the SEC for detailed information about derivative instruments the company uses, its quarter-end derivative positions and the accounting for natural gas, oil and NGL derivatives.

As of November 1, 2012, the company has the following open natural gas swaps in place and gains (losses) related to closed natural gas trades and premiums for call options for future production periods.

	Open Swaps (bcf)	Avg. NYMEX Price of Open Swaps	Forecasted Natural Gas Production (bcf)	Open Swap Positions as a % of Forecasted Natural Gas Production	Total Gains (Losses) from Closed Trades and Premiums for Call Options ($ in millions)	Total Gains from Closed Trades and Premiums for Call Options per mcf of Forecasted Natural Gas Production
Q4 2012	215	$ 3.06	281	76%	$ 15	$ 0.05
Q1 2013	0				$ (11)	
Q2 2013	0				8	
Q3 2013	0				6	
Q4 2013	0				(3)	
Total 2013	0	$ 0.00	1,050	0%	$ 0	$ 0.00
Total 2014	0				$ (74)	
Total 2015	0				$ (131)	
Total 2016 – 2022	0				$ (161)	

The company currently has the following natural gas written call options in place:

	Call Options (bcf)	Avg. NYMEX Strike Price	Forecasted Natural Gas Production (bcf)	Call Options as a % of Forecasted Natural Gas Production
Q4 2012	40	$ 3.25	281	14%
Total 2013	0	$ 0.00	1,050	0%
Total 2014	0	$ 0.00		
Total 2015	0	$ 0.00		
Total 2016 – 2020	260	$ 8.90		

The company currently has the following purchased natural gas put swaptions in place:

	Put Swaptions (bcf)	Avg. NYMEX Price of Swap	Forecasted Natural Gas Production (bcf)	Put Swaption as a % of Forecasted Natural Gas Production
Q1 2013	8	$ 3.66		
Q2 2013	10	$ 3.64		
Q3 2013	2	$ 3.50		
Q4 2013	0	$ 0.00		
Total 2013	20	$ 3.64	1,050	2%

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

	Volume (Bcf)	Avg. NYMEX less
Q4 2012	8	$0.74
2013	44	$0.21
2014	28	$0.32
2015 - 2022	40	$0.48

As of November 1, 2012, the company has the following open crude oil swaps in place and gains (losses) related to closed crude oil contracts and premiums for call options for future production periods (note: the company also has 5,000 bbls per day of propane call options in Q4 2012):

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps	Forecasted Oil Production (mbbls)	Open Swap Positions as a % of Forecasted Oil Production	Total Gains (Losses) from Closed Trades and Premiums for Call Options ($ in millions)	Total Gains (Losses) from Closed Trades and Premiums for Call Options per bbl of Forecasted Oil Production
Q4 2012	6,197	$ 99.14	8,171	76%	$ (31)	$ (3.83)
Q1 2013	5,647	95.95			$ 1	
Q2 2013	6,672	96.10			$ 1	
Q3 2013	6,687	96.02			$ 2	
Q4 2013	6,662	95.97			$ 2	
Total 2013	25,668	$ 96.01	37,000	69%	$ 6	$ 0.17
Total 2014	918	$ 90.85			$ (151)	
Total 2015	500	$ 88.75			$ 265	
Total 2016 – 2021	0				$ 117	

The company currently has the following crude oil written call options in place:

	Call Options (mbbls)	Avg. NYMEX Strike Price	Forecasted Oil Production (mbbls)	Call Options as a % of Forecasted Oil Production
Q4 2012	0	$ --	8,171	0%
Q1 2013	3,390	$ 99.56		
Q2 2013	3,428	$ 99.56		
Q3 2013	3,006	$ 98.62		
Q4 2013	3,006	$ 98.62		
Total 2013	12,830	$ 99.12	37,000	35%
Total 2014	17,612	$ 98.79		
Total 2015	27,048	$ 100.99		
Total 2016 – 2017	24,220	$ 100.07		

The company has the following oil basis protection swaps in place:

	Volume (mbbls)	Avg. NYMEX plus
Q4 2012	951	$17.70
Q1 2013	2,070	$14.99
Q2 2013	1,365	$12.55
Total 2013	3,435	$14.02