NEWS RELEASE

Chesapeake Energy Corporation Provides Operational Update

2009 Fourth Quarter Production of 2.6 Bcfe per Day Increases 13% Over 2008 Fourth Quarter Production2009 Full Year Production of 2.5 Bcfe per Day Increases 8% Over 2008 Full Year Production, Setting Record for 20th Consecutive Year Proved Reserves Reach 14.3 Tcfe Using SEC Pricing and 15.5 Tcfe Using 10-Year Average NYMEX Strip Pricing, Year-Over-Year Increases of 18% and 29%, Respectively Company Delivers 2009 Full Year Reserve Replacement Ratio and Drilling and Net Acquisition Cost of343% and $0.74 per Mcfe, Respectively, Using SEC Pricing and 485% and $0.73 per Mcfe, Respectively, Using 10-Year Average NYMEX Strip Pricing

OKLAHOMA CITY, Feb 16, 2010 (BUSINESS WIRE) -- Chesapeake Energy Corporation (NYSE:CHK) today provided an update on its operational activities. For the 2009 fourth quarter, Chesapeake's daily production averaged 2.618 billion cubic feet of natural gas equivalent (bcfe), an increase of 135 million cubic feet of natural gas equivalent (mmcfe), or 5%, over the 2.483 bcfe produced per day in the 2009 third quarter and an increase of 302 mmcfe, or 13%, over the 2.316 bcfe produced per day in the 2008 fourth quarter. Adjusted for the company's voluntary production curtailments due to low natural gas prices (approximately 26 mmcfe per day during the 2009 fourth quarter), the company's volumetric production payment transactions (which combined averaged approximately 96 mmcfe per day during the 2009 fourth quarter) and the estimated impact from various divestitures (which would have averaged approximately 49 mmcfe per day during the 2009 fourth quarter), Chesapeake's sequential and year-over-year production growth rates would have been 5% and 17%, respectively, after making similar adjustments to prior quarters. Chesapeake's 2009 fourth quarter average daily production of 2.618 bcfe consisted of 2.440 billion cubic feet of natural gas (bcf) and 29,750 barrels of oil and natural gas liquids (bbls). The company's 2009 fourth quarter production of 241 bcfe was comprised of 225 bcf (93% on a natural gas equivalent basis) and 2.7 million barrels of oil and natural gas liquids (mmbbls) (7% on a natural gas equivalent basis).

The company's daily production for the 2009 full year averaged 2.481 bcfe, an increase of 178 mmcfe, or 8%, over the 2.303 bcfe of daily production for the 2008 full year. Adjusted for the company's voluntary production curtailments due to low natural gas prices (approximately 47 mmcfe per day during the 2009 full year), the company's volumetric production payment transactions (which combined averaged approximately 157 mmcfe per day during the 2009 full year) and the estimated impact from various divestitures (which would have averaged approximately 193 mmcfe per day during the 2009 full year), Chesapeake's year-over-year daily production growth rate would have been 19%, after making similar adjustments to the 2008 full year. Chesapeake's average daily production for the 2009 full year of 2.481 bcfe consisted of 2.287 bcf and 32,301 bbls. The company's 2009 full year production of 906 bcfe was comprised of 835 bcf (92% on a natural gas equivalent basis) and 11.8 mmbbls (8% on a natural gas equivalent basis). The 2009 full year was Chesapeake's 20th consecutive year of sequential production growth. Chesapeake anticipates delivering full-year production growth of approximately 8-10% in 2010 and 15-17% in 2011, net of property divestitures.

Proved Reserves Reach Record Levels and Company Delivers Drilling and Net Acquisition Costs of $0.74 per Mcfe

For year-end 2009 reserve reporting, the Securities and Exchange Commission (SEC) has implemented new rules requiring that proved reserve calculations be based on the unweighted average first-of-the-month prices for the twelve months in 2009, as contrasted with the previous method which utilized period-end prices. The prices under the new method were $3.87 per mcf and $61.14 per bbl, before field differential adjustments, compared to year-end 2009 spot prices of $5.79 per mcf and $79.34 per bbl, before field differential adjustments. The modernized rules also contain new reserve recognition definitions that allow for the reporting of proved undeveloped (PUD) reserves that are more than one direct development spacing area away from offsetting producing wells if reasonable certainty can be shown using reliable technology. Chesapeake has utilized and developed reliable geologic and engineering technology to book PUD reserves more than one location offsetting production in the Barnett Shale and Fayetteville Shale. At the present time, PUD reserve bookings in all other asset areas have been restricted to directly offsetting development spacing areas away from offsetting producing wells.

The SEC's new pricing rule reflects the low average natural gas prices experienced in 2009. This affects the volume of reportable proved reserves and substantially lowers the estimated future net cash flows from proved reserves. Chesapeake believes that using the 10-year average NYMEX strip prices as of December 31, 2009, which were $6.94 per mcf and $92.24 per bbl, before field differential adjustments, yields a better indication of the likely economic producibility of its proved reserves than the 2009 12-month average required by the new rules or spot prices at year end, which were required prior to year-end 2009.

The following table compares Chesapeake's year-end 2009 proved reserves and percentage increase over its year-end 2008 proved reserves of 12.1 tcfe, estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10), and proved developed percentage based on the 2009 12-month average price required under new SEC rules, spot prices at year-end 2009 and the 10-year average NYMEX strip prices at year-end 2009.

Pricing Assumption	Natural Gas Price ($/mcf)	Oil Price ($/bbl)	Proved Reserves (tcfe)	Proved Reserves Annual Growth Rate	Reserve Replacement Ratio	PV-10 (billions)	Proved Developed Percentage
2009 12-month average (SEC)	$3.87	$61.14	14.3	18%	343%	$9.4 (a)	58%
12/31/09 spot	$5.79	$79.34	15.3	27%	460%	$21.4	58%
12/31/09 10-year average NYMEX strip	$6.94	$92.24	15.5	29%	485%	$28.7	58%

(a) The associated standardized measure of discounted future net cash flows, which includes the effect of future income taxes, was $8.2 billion under SEC pricing.

The following table summarizes Chesapeake's finding and development costs for the 2009 full year using each of the three pricing assumptions described above.

Finding and Development Cost Category	12-Month Average (SEC) Pricing ($/mcfe)	12/31/09 Spot Pricing ($/mcfe)	12/31/09 10-year Average NYMEX Strip Pricing ($/mcfe)
Exploration and development costs (a)	$0.80	$0.80	$0.79
Drilling and net acquisition costs (a)	$0.74	$0.74	$0.73
Total costs	$1.50	$1.12	$1.06

(a) Includes performance-related revisions and the benefit of $1.154 billion in drilling carries and also excludes price-related revisions

A complete reconciliation of proved reserves, reserve replacement ratios and finding and acquisition costs based on these three alternative pricing assumptions is presented on pages 10 - 12 of this release. Also, a reconciliation of PV-10 to the standardized measure is presented on page 13 of this release.

In addition to the PV-10 value of its proved reserves and the very significant value of its undeveloped leasehold, particularly in the Haynesville, Marcellus, Barnett and Fayetteville Shale plays and the Greater Granite Wash plays, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments and other non-current assets) was $6.7 billion as of December 31, 2009 compared to $5.8 billion as of December 31, 2008.

During 2009, Chesapeake continued the industry's most active drilling program and drilled 1,148 gross operated wells (831 net wells with an average working interest of 72%) and participated in another 1,126 gross wells operated by other companies (99 net wells with an average working interest of 9%). The company's drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during 2009, Chesapeake invested $2.941 billion in operated wells (using an average of 104 operated rigs) and $439 million in non-operated wells (using an average of 60 non-operated rigs) for total drilling, completing and equipping costs of $3.380 billion.

Chesapeake's Leasehold and 3-D Seismic Inventories Total 13.7 Million Net Acres and 23.6 Million Acres; Risked Unproved Resources in the Company's Inventory Total 65 Tcfe and Unrisked Unproved Resources Total 177 Tcfe

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.7 million net acres) and 3-D seismic (23.6 million acres) in the U.S. and the largest inventory of U.S. Big 6 shale play leasehold (2.9 million net acres) and Granite Wash leasehold (190,000 net acres). On its leasehold, as of December 31, 2009, pro forma for the company's January 2010 Barnett Shale joint venture transaction, Chesapeake had identified an estimated 14.6 tcfe of proved reserves and 65 tcfe of risked unproved resources (177 tcfe of unrisked unproved resources), based on the year-end 2009 10-year average NYMEX strip prices. The company is currently using 118 operated drilling rigs to further develop its inventory of approximately 35,750 net drillsites, which represents more than a 10-year inventory of drilling projects.

The following table summarizes Chesapeake's ownership and activity in its Big 6 shale plays, its two primary Anadarko Basin Granite Wash plays and its other plays. Chesapeake uses a probability-weighted statistical approach to estimate the potential number of drillsites and unproved resources associated with such drillsites.

Play Type/Area	CHK Net Acreage[1]	Est. Drilling Density (Acres)	Risk Factor	Risked Net Undrilled Wells[1]	Est. Avg. Resources Per Well (bcfe)	Proved Reserves (bcfe)[1][2]	Risked Unproved Resources (bcfe)[2]	Unrisked Unproved Resources (bcfe)[2]	Current Daily Net Production (mmcfe)[1]	Current Operate Rig Count[4

									(3)	
Big 6 Shale Plays:										
Marcellus Shale	1,570,000	80	70%	5,900	4.20	265	20,900	69,900	65	24
Haynesville Shale	535,000	80	40%	3,900	6.50	1,960	17,400	30,100	375	38
Fayetteville Shale	455,000	80	20%	4,200	2.40	2,225	6,900	9,000	340	12
Barnett Shale[1]	220,000	60	15%	1,800	2.65	2,756	2,800	3,800	515	24
Bossier Shale	180,000	80	80%	450	5.50	0	1,900	9,300	ND[6]	0
Eagle Ford Shale[7]	80,000	160	90%	50	4.30	0	200	1,600	ND[6]	1
Big 6 Shale Play Subtotal[5]	**2,860,000**			**16,300**		**7,206**	**50,100**	**123,700**	**1,295**	**99**
Colony Granite Wash	120,000	160	25%	500	5.70	443	1,900	2,700	110	4
Texas Panhandle Granite Wash	70,000	80	25%	400	4.75	670	1,200	1,700	90	4
Other	10,650,000	Various	Various	18,550	Various	6,303	11,300	48,600	920	11
Total	**13,700,000**			**35,750**		**14,622**	**64,500**	**176,700**	**2,415**	**118**

(1) Pro forma for January 2010 Barnett Shale joint venture transaction

(2) Based on year-end 2009 10-Year average NYMEX strip pricing

(3) Estimated February 2010 average

(4) As of February 12, 2010

(5) Bossier Shale acreage overlaps with Haynesville Shale acreage and is excluded from the Big 6 acreage subtotal to avoid double counting of acreage

(6) Not disclosed

(7) As of February 17, 2010, Chesapeake's Eagle Ford Shale acreage is approximately 150,000 net acres

Marcellus Shale (West Virginia, Pennsylvania and New York): With approximately 1.6 million net acres, Chesapeake is the largest leasehold owner in the Marcellus Shale play that spans from northern West Virginia across much of Pennsylvania into southern New York. The company's joint venture partner, Statoil (NYSE:STO, OSE:STL), owns approximately 590,000 additional net acres of Marcellus leasehold. Chesapeake remains the most active driller in the play. Since January 1, 2008, Chesapeake has drilled and completed 56 company-operated horizontal wells in the Marcellus. During the 2009 fourth quarter, Chesapeake's average daily net production of approximately 45 mmcfe in the Marcellus increased approximately 26% over the 2009 third quarter and approximately 530% over the 2008 fourth quarter. Chesapeake is currently producing a company record monthly average of approximately 65 mmcfe net per day (115 mmcfe gross operated) from the Marcellus and anticipates reaching approximately 270 mmcfe net per day (515 mmcfe gross operated) by year-end 2010 and approximately 450 mmcfe net per day (855 mmcfe gross operated) by year-end 2011.

To further develop its 1.6 million net acres of Marcellus leasehold, Chesapeake is currently drilling with 24 operated rigs and anticipates operating an average of approximately 32 rigs in 2010 to drill approximately 175 net wells. During 2009, approximately $162 million of Chesapeake's drilling costs in the Marcellus were paid for by STO. During 2010 through 2012, 75% of Chesapeake's drilling costs in the Marcellus will be paid for by STO, or approximately $2.0 billion over the next three years.

Chesapeake's leasehold investment in the Marcellus has been approximately $1.8 billion, of which $1.3 billion, or 70%, has been recouped by selling a 32.5% interest in the company's leasehold to STO. The company's net investment in its Marcellus leasehold is now approximately $330 per net acre on average.

Three notable recent wells completed by Chesapeake in the Marcellus are as follows:

- The White 2H in Susquehanna County, PA achieved a peak 24-hour rate of 8.7 mmcf per day;
- The White 5H in Susquehanna County, PA achieved a peak 24-hour rate of 8.6 mmcf per day; and
- The Benscoter 3H in Susquehanna County, PA achieved a peak 24-hour rate of 8.4 mmcf per day.

Haynesville Shale (Northwest Louisiana, East Texas): Chesapeake is the largest leasehold owner and most active driller of new wells in the Haynesville Shale play in Northwest Louisiana and East Texas. Chesapeake now owns approximately 535,000 net acres of leasehold in the Haynesville Shale play. Chesapeake and its 20% joint venture partner, Plains Exploration & Production Company (NYSE:PXP) (which owns approximately 110,000 additional net acres), have drilled and completed 150 Chesapeake-operated horizontal wells in the Haynesville play and continue to experience outstanding drilling results. During the 2009 fourth quarter, Chesapeake's average daily net production of approximately 365 mmcfe in the Haynesville increased approximately 59% over the 2009 third quarter and approximately 519% over the 2008 fourth quarter. Chesapeake is currently producing approximately 375 mmcfe net per day (550 mmcfe gross operated) from the Haynesville and anticipates exceeding approximately 640 mmcfe net per day (970 mmcfe gross operated) by year-end 2010 and approximately 810 mmcfe net per day (1,230 mmcfe gross operated) by year-end 2011.

To further develop its 535,000 net acres of Haynesville leasehold, Chesapeake is currently drilling with 38 operated rigs and anticipates operating an average of approximately 41 rigs in 2010 to drill approximately 200 net wells. During 2009, approximately $390 million of Chesapeake's drilling costs in the Haynesville were paid for by its joint venture partner PXP. In August 2009, Chesapeake and PXP amended their joint venture agreement to accelerate the payment of PXP's remaining joint venture drilling carries as of September 30, 2009 in exchange for an approximate 12% reduction in the total amount of drilling carry obligations due to Chesapeake. As a result, on September 29, 2009, Chesapeake received $1.1 billion in cash from PXP and beginning in the 2009 fourth quarter Chesapeake and PXP each began paying their proportionate working interest costs on drilling.

Chesapeake's leasehold investment in the Haynesville has been approximately $5.3 billion, of which approximately $2.8 billion, or 52%, has been recouped by selling a 20% interest in the company's leasehold to PXP. The company's net investment in its Haynesville leasehold is now approximately $4,600 per net acre on average.

Three notable recent wells completed by Chesapeake in the Haynesville are as follows:

- The Sloan 4-12-13 H-1 in De Soto Parish, LA achieved a peak 24-hour rate of 23.4 mmcf per day;
- The Johnson 21-13-13 H-1 in De Soto Parish, LA achieved a peak 24-hour rate of 18.5 mmcf per day; and
- The Caspiana 14-15-12H-1 in Caddo Parish, LA achieved a peak 24-hour rate of 18.4 mmcf per day.

Fayetteville Shale (Arkansas): The Fayetteville Shale is currently the second most productive shale play in the U.S. and one of the nation's ten largest natural gas fields of any type. In the Fayetteville, Chesapeake is the second-largest leasehold owner in the Core area of the play with 455,000 net acres. During the 2009 fourth quarter, Chesapeake's average daily net production of approximately 310 mmcfe in the Fayetteville increased approximately 25% over the 2009 third quarter and approximately 85% over the 2008 fourth quarter. Chesapeake is currently producing approximately 340 mmcfe net per day (490 mmcfe gross operated) from the Fayetteville and anticipates maintaining approximately 320 mmcfe net per day (460 mmcfe gross operated) through year-end 2011.

To further develop its 455,000 net acres of Core Fayetteville leasehold, Chesapeake anticipates operating an average of approximately 12 rigs in 2010 to drill approximately 110 net wells. During 2009, $601 million of Chesapeake's drilling costs in the Fayetteville were paid for by its joint venture partner, BP America (NYSE:BP). During the fourth quarter 2009, BP paid Chesapeake the remaining balance of BP's drilling carry obligations and Chesapeake and BP each began paying their proportionate working interest costs on drilling.

Chesapeake's leasehold investment in the Fayetteville to date has been approximately $532 million. By selling a 25% interest in the company's leasehold to BP for $883 million, the company has more than recouped its entire leasehold investment in the Fayetteville, resulting in a per net acre cost of less than zero.

Three notable recent wells completed by Chesapeake in the Fayetteville are as follows:

- The Nicholson 7-8 4-10H9 in White County, AR achieved a peak 24-hour rate of 9.2 mmcf per day;
- The Stroud 7-9 1-23H14 in White County, AR achieved a peak 24-hour rate of 7.9 mmcf per day; and
- The Gardner 10-13 2-21H in Van Buren County, AR achieved a peak 24-hour rate of 6.2 mmcf per day.

Barnett Shale (North Texas): The Barnett Shale is currently the largest natural gas producing field in the U.S. and is producing approximately 50% of all shale gas in the U.S. In this play, Chesapeake is the second-largest producer, the most active driller and the largest leasehold owner in the Core and Tier 1 sweet spots of Tarrant and Johnson counties. In January 2010, Chesapeake completed its $2.25 billion Barnett Shale joint venture transaction with Total E&P USA, Inc., a wholly-owned subsidiary of Total S.A. (NYSE:TOT, FP:FP) (Total), whereby Total acquired a 25% interest in Chesapeake's upstream Barnett Shale assets. Total paid Chesapeake approximately $800 million in cash at closing and will pay a further $1.45 billion over time by funding 60% of Chesapeake's share of drilling and completion expenditures until the $1.45 billion obligation has been funded, which Chesapeake expects to occur by year-end 2012.

During the 2009 fourth quarter, Chesapeake’s average daily net production of approximately 680 mmcfe in the Barnett increased approximately 7% over the 2009 third quarter and increased approximately 19% over the 2008 fourth quarter. Chesapeake is currently producing approximately 515 mmcfe net per day (950 mmcfe gross operated) from the Barnett (net production was reduced by 25% as a result of the joint venture with Total) and anticipates reaching approximately 590 mmcfe net per day (1,120 mmcfe gross operated) by year-end 2010 and approximately 665 mmcfe net per day (1,260 mmcfe gross operated) by year-end 2011.

To further develop its 220,000 net acres of leasehold, Chesapeake anticipates operating an average of approximately 28 rigs in 2010 to drill approximately 300 net wells.

Chesapeake’s leasehold investment in the Barnett has been approximately $4.0 billion, of which $1.1 billion, or 26%, will be recouped through the 25% sale of Chesapeake’s interest in its leasehold to Total. The company’s net investment in its Barnett leasehold is now approximately $13,400 per net acre on average.

Three notable recent wells completed by Chesapeake in the Barnett are as follows:

- The Auld 1H in Ellis County, TX achieved a peak 24-hour rate of 13.0 mmcf per day;
- The Crowley Eagles 4H in Tarrant County, TX achieved a peak 24-hour rate of 10.4 mmcf per day; and
- The Crowley Eagles 1H in Tarrant County, TX achieved a peak 24-hour rate of 9.6 mmcf per day.

Anadarko Basin Granite Wash (western Oklahoma and Texas Panhandle): In the various Granite Wash plays of the Anadarko Basin, Chesapeake is the largest leasehold owner with approximately 190,000 net acres and is also the most active driller and largest producer. The Colony Granite Wash and the Texas Panhandle Granite Wash plays highlighted below are two particularly prolific areas within the Anadarko Basin Granite Wash and have become the two highest rate-of-return plays in the company.

Colony Granite Wash (western Oklahoma): Discovered by Chesapeake in February 2007, the Colony Granite Wash play is primarily located in Custer and Washita counties in Oklahoma and is a subset of the greater Granite Wash plays of the Anadarko Basin. In the Colony Granite Wash, Chesapeake is the largest leasehold owner with 120,000 net acres and is also the most active driller and largest producer in the play. During the 2009 fourth quarter, Chesapeake’s average daily net production of approximately 105 mmcfe in the Colony Granite Wash was approximately flat to the 2009 third quarter and increased approximately 47% over the 2008 fourth quarter. Chesapeake is currently producing approximately 110 mmcfe net per day (200 mmcfe gross operated) from the Colony Granite Wash and anticipates producing approximately 190 mmcfe net per day (350 mmcfe gross operated) by year-end 2010 and approximately 230 mmcfe net per day (420 mmcfe gross operated) by year-end 2011.

To further develop its 120,000 net acres of Colony Granite Wash leasehold, Chesapeake anticipates operating an average of approximately seven rigs in 2010 to drill approximately 40 net wells. Due in large part to the play’s high oil and natural gas liquids content, the Colony Granite Wash is Chesapeake’s second highest rate-of-return play.

Three notable recent wells completed by Chesapeake in the Colony Granite Wash are as follows:

- The Shirl Ann 1-14H in Washita County, OK achieved a peak 24-hour rate of 21.8 mmcfe per day
- The Lee Roy 1-24H in Washita County, OK achieved a peak 24-hour rate of 21.6 mmcfe per day; and
- The Javorsky 1-33H in Washita County, OK achieved a peak 24-hour rate of 20.6 mmcfe per day.

Texas Panhandle Granite Wash: The Texas Panhandle Granite Wash play is located in Hemphill, Wheeler and Roberts counties in Texas and is a subset of the greater Granite Wash plays of the Anadarko Basin. In the Texas Panhandle Granite Wash, Chesapeake is one of the largest leasehold owners with 70,000 net acres and also one of the most active drillers and largest producers in the play. During the 2009 fourth quarter, Chesapeake’s average daily net production of approximately 100 mmcfe in the Texas Panhandle Granite Wash increased approximately 24% over the 2009 third quarter and increased approximately 20% over the 2008 fourth quarter. Chesapeake is currently producing approximately 90 mmcfe net per day (130 mmcfe gross operated) from the Texas Panhandle Granite Wash and anticipates producing approximately 125 mmcfe net per day (180 mmcfe gross operated) by year-end 2010 and approximately 130 mmcfe net per day (185 mmcfe gross operated) by year-end 2011.

To further develop its 70,000 net acres of Texas Panhandle Granite Wash leasehold, Chesapeake anticipates operating an average of four rigs in 2010 to drill approximately 30 net wells. Due in large part to the play’s high oil and natural gas liquids content, the Texas Panhandle Granite Wash is Chesapeake’s highest rate-of-return play.

Three notable recent wells completed by Chesapeake in the Texas Panhandle Granite Wash are as follows:

- The Ruby Lee 102H in Wheeler County, TX achieved a peak 24-hour rate of 17.8 mmcfe per day;
- The Ruby Lee 103H in Wheeler County, TX achieved a peak 24-hour rate of 12.8 mmcfe per day; and
- The Reed T 8H in Wheeler County, TX achieved a peak 24-hour rate of 10.6 mmcfe per day.

2009 Fourth Quarter and Full Year Financial and Operational Results Conference Call Information

Chesapeake is scheduled to release its 2009 fourth quarter and full year financial results after the close of trading on the New York Stock Exchange on Wednesday, February 17, 2010. Also, a conference call to discuss this release of operational results and the February 17 release of financial results has been scheduled for Thursday, February 18, 2010, at 9:00 a.m. EST. The telephone number to access the conference call is **913-312-0688** or toll-free **800-930-1344**. The passcode for the call is **2347767**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 9:00 a.m. EST. For those unable to participate in the conference call, a replay will be available for audio playback from 1:00 p.m. EST on February 18, 2010 through midnight EST on March 4, 2010. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **2347767**. The conference call will also be webcast live on the Internet and can be accessed by going to Chesapeake's website at www.chk.com in the "Events" subsection of the "Investors" section of our website. The webcast of the conference call will be available on our website for one year.

This press release includes "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 natural gas and oil reserves under different pricing assumptions, expected natural gas and oil production, expectations regarding future natural gas and oil prices and costs, and planned drilling activity. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in our 2008 Form 10-K and 2009 second quarter Form 10-Q filed with the U.S. Securities and Exchange Commission on March 2, 2009 and August 10, 2009, respectively. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; impacts the current economic downturn may have on our business and financial condition; 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 planned asset monetization transactions, 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; exploration and development drilling that does not result in commercially productive reserves; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities; uncertainties in evaluating natural gas and oil reserves of acquired properties and potential liabilities; the negative impact lower natural gas and oil prices could have on our ability to borrow; drilling and operating risks, including potential environmental liabilities; transportation capacity constraints and interruptions that could adversely affect our cash flow; potential increased operating costs resulting from proposed legislative and regulatory changes affecting our operations; and adverse results in pending or future litigation.

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

The SEC requires natural gas and oil companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of natural gas and oil that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. For filings reporting year-end 2009 reserves, the SEC permits the optional disclosure of probable and possible reserves. Chesapeake has elected not to report probable and possible reserves in its filings with the SEC. In this press release, we use the terms "risked and unrisked unproved resources" and "estimated average resources per well" to describe Chesapeake's internal estimates of volumes of natural gas and oil that are not classified as proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques. These may be broader descriptions of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. Estimates of unproved resources are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. We believe our estimates of unproved resources, both risked and unrisked, are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of unproved resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.

Chesapeake Energy Corporation is the second-largest producer of natural gas in the U.S. Headquartered in Oklahoma City, the company's operations are focused on the development of onshore unconventional and conventional natural gas in the U.S. in the Barnett Shale, Haynesville Shale, Fayetteville Shale, Marcellus Shale, Anadarko Basin, Arkoma Basin, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and East Texas regions of the United

States. Further information is available at www.chk.com.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2009 ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
BASED ON SEC PRICING OF 2009 AVERAGE 12-MONTH PRICES
($ in millions, except per-unit data)
(unaudited)

	Cost	Proved Reserves Bcfe[a]	$/mcfe
Exploration and development costs	$ 3,380	4,248 (b)	0.80
Acquisition of proved properties	61	33	1.84
Sale of proved properties	(576)	(220)	2.61
Other	131	--	--
Drilling and net acquisition costs	2,996	4,061	0.74
Revisions - price	--	(952)	--
Acquisition of unproved properties and leasehold	2,195	--	--
Sale of unproved properties and leasehold	(1,281)	--	--
Net unproved properties and leasehold acquisition	914	--	--
Capitalized interest on leasehold and unproved property	627	--	--
Geological and geophysical costs	133	--	--
Capitalized interest and geological and geophysical costs	760	--	--
Subtotal	4,670	3,109	1.50
Asset retirement obligation and other	(2)	--	--
Total costs	$ 4,668	3,109	1.50

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
TWELVE MONTHS ENDED DECEMBER 31, 2009
BASED ON SEC PRICING OF 2009 AVERAGE 12-MONTH PRICES
(unaudited)

	Bcfe[a]	
Beginning balance, 01/01/09	12,051	
Production	(906	)
Acquisitions	33	
Divestitures	(220	)
Revisions - changes to previous estimates	(445	)
Revisions - price	(952	)
Extensions and discoveries	4,693	
Ending balance, 12/31/09	14,254	
Proved reserves annual growth rate	18	%
Proved developed reserves	8,331	
Proved developed reserves percentage	58	%
Reserve replacement	3,109	
Reserve replacement ratio [c]	343	%

(a) Reserve volumes estimated using new SEC reserve recognition standards and pricing assumptions based on the 2009 unweighted average first-day-of-the-month prices of $3.87 per mcf of natural gas and $61.14 per bbl of oil, before field differential adjustments.

(b) Includes 445 bcfe of negative revisions resulting from changes to previous estimates and excludes downward revisions of 952 bcfe resulting from a lower natural gas price using the average 12-month price in 2009 compared to the NYMEX spot price as of December 31, 2008.

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

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2009 ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
BASED ON SPOT PRICES AT DECEMBER 31, 2009
($ in millions, except per-unit data)
(unaudited)

	Proved Reserves Cost	Bcfe[(a)]	$/mcfe
Exploration and development costs	$3,380	4,241[(b)]	0.80
Acquisition of proved properties	61	39	1.57
Sale of proved properties	(576)	(220)	2.61
Other	131	--	--
Drilling and net acquisition costs	2,996	4,060	0.74
Revisions - price	--	104	--
Acquisition of unproved properties and leasehold	2,195	--	--
Sale of unproved properties and leasehold	(1,281)	--	--
Net unproved properties and leasehold acquisition	914	--	--
Capitalized interest on leasehold and unproved property	627	--	--
Geological and geophysical costs	133	--	--
Capitalized interest and geological and geophysical costs	760	--	--
Subtotal	4,670	4,164	1.12
Asset retirement obligation and other	(2)	--	--
Total costs	$4,668	4,164	1.12

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
TWELVE MONTHS ENDED DECEMBER 31, 2009
BASED ON SPOT PRICES AT DECEMBER 31, 2009
(unaudited)

	Bcfe[(a)]
Beginning balance, 01/01/09	12,051
Production	(906)
Acquisitions	39
Divestitures	(220)
Revisions - changes to previous estimates	(515)
Revisions - price	104
Extensions and discoveries	4,756
Ending balance, 12/31/09	15,309
Proved reserves annual growth rate	27 %
Proved developed reserves	8,828
Proved developed reserves percentage	58 %
Reserve replacement	4,164
Reserve replacement ratio [(c)]	460 %

(a) Reserve volumes estimated using new SEC reserve recognition standards and NYMEX spot prices at December 31, 2009 of $5.79 per mcf of natural gas and $79.34 per bbl of oil, before field differential adjustments.

(b) Includes 515 bcfe of negative revisions resulting from changes to previous estimates and excludes upward revisions of 104 bcfe resulting from higher natural gas and oil prices using NYMEX spot prices as of December 31, 2009 compared to NYMEX spot prices as of December 31, 2008.

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

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF 2009 ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
BASED ON 10-YEAR AVERAGE NYMEX STRIP PRICES AT DECEMBER 31, 2009
($ in millions, except per-unit data)
(unaudited)

	Proved Reserves		
	Cost	**Bcfe[a]**	**$/mcfe**
Exploration and development costs	$3,380	4,303[b]	0.79
Acquisition of proved properties	61	40	1.52
Sale of proved properties	(576)	(220)	2.61
Other	131	--	--
Drilling and net acquisition costs	2,996	4,123	0.73
Revisions - price	--	272	--
Acquisition of unproved properties and leasehold	2,195	--	--
Sale of unproved properties and leasehold	(1,281)	--	--
Net unproved properties and leasehold acquisition	914	--	--
Capitalized interest on leasehold and unproved property	627	--	--
Geological and geophysical costs	133	--	--
Capitalized interest and geological and geophysical costs	760	--	--
Subtotal	4,670	4,395	1.06
Asset retirement obligation and other	(2)	--	--
Total costs	$4,668	4,395	1.06

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
TWELVE MONTHS ENDED DECEMBER 31, 2009
BASED ON 10-YEAR AVERAGE NYMEX STRIP PRICES AT DECEMBER 31, 2009
(unaudited)

	Bcfe[a]
Beginning balance, 01/01/09	12,051
Production	(906)
Acquisitions	40
Divestitures	(220)
Revisions - changes to previous estimates	(477)
Revisions - price	272
Extensions and discoveries	4,780
Ending balance, 12/31/09	15,540
Proved reserves annual growth rate	29 %
Proved developed reserves	9,005
Proved developed reserves percentage	58 %
Reserve replacement	4,395
Reserve replacement ratio [c]	485 %

(a) Reserve volumes estimated using new SEC reserve recognition standards and 10-year average NYMEX strip prices as of December 31, 2009 of $6.94 per mcf of natural gas and $92.24 per bbl of oil, before field differential adjustments. Chesapeake uses such forward-looking market-based data in developing its drilling plans, assessing its capital expenditure needs and projecting future cash flows. Chesapeake believes these prices are better indicators of the likely economic producibility of proved reserves than the trailing average 12-month price required by the SEC's reporting rule or a period-end spot price, as previously required in SEC reporting.

(b) Includes 477 bcfe of negative revisions resulting from changes to previous estimates and excludes upward revisions of 272 bcfe resulting from higher natural gas and oil prices using 10-year average NYMEX strip prices as of December 31, 2009 compared to NYMEX spot prices as of December 31, 2008.

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

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

	December 31, 2009	December 31, 2008
Standardized measure of discounted future net of cash flows	$ 8,203	$ 11,833
Discounted future cash flows for income taxes	1,246	3,768
Discounted future net cash flows before income taxes (PV-10)	$ 9,449	$ 15,601

PV-10 is discounted (at 10%) 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 GAAP. Management uses PV-10 as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While PV-10 is based on prices, costs and discount factors which are consistent from company to company, the standardized measure is dependant on the unique tax situation of each individual company.

The company's December 31, 2009 PV-10 and standardized measure were calculated using the unweighted average first-of-the-month prices for the twelve months in 2009 of $3.87 per mcf and $61.14 per bbl, before field differential adjustments. The company's December 31, 2008 PV-10 and standardized measure were calculated using year-end 2008 spot prices of $5.71 per mcf and $44.61 per bbl, before field differential adjustments.

SOURCE: Chesapeake Energy Corporation

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