

**For immediate release**

Company contact: Jennifer Martin, Vice President - Investor Relations, 303-312-8155

**Bill Barrett Corporation Reports Second Quarter 2011 Results  
and Announces Positive Initial Rates from Uteland Butte Exploration Wells**

DENVER – August 4, 2011 – Bill Barrett Corporation (NYSE: BBG) today reported second quarter 2011 operating results highlighted by:

- Natural gas and oil production growth, up 6% to 26.5 Bcfe compared with the second quarter of 2010
- Discretionary cash flow growth, up 6% to \$122.8 million or \$2.61 per diluted common share compared with the second quarter of 2010
- Net income of \$32.6 million or \$0.69 per diluted common share and adjusted net income of \$27.6 million or \$0.59 per diluted common share
- Uteland Butte horizontal exploration well with positive initial flow rates
- Key Uinta Basin East Bluebell oil acquisition closed adding 5 MMBoe proved reserves with 20,300 net acres
- Denver-Julesburg exploration and development position to be acquired including 7 MMBoe proved reserves and 28,000 net acres, complementing existing 38,200 acre position

Chairman, Chief Executive Officer and President Fred Barrett commented: “We enjoyed a terrific second quarter with several highlights to report. Strong second quarter cash flow and earnings reflect our success in ramping up West Tavaputs operations quickly and efficiently as well as growing the oil component in our portfolio from the Uinta Basin. Comparing sequentially the second quarter to the first quarter of 2011, West Tavaputs production was up a dramatic 57% and Uinta Basin oil production was up more than 30%. While we are executing on strong production growth from our development portfolio, we also pursued future growth through two bolt-on acquisitions that offer existing oil production and reserves with sizable upside potential, located in the Uinta and DJ Basins –areas of Bill Barrett Corporation expertise.

“We are also announcing today drilling results from our first Uteland Butte formation horizontal well in Lake Canyon. The first well had an average rate of 717 barrels of oil equivalent per day (“Boe/d”) over the first 30 days of production. While it is too early to estimate EURs, we are encouraged by the performance to date. Success in the Uteland Butte would open the potential for inventory expansion at Blacktail Ridge-Lake Canyon, where we have a vast undeveloped acreage position, as well as increase the recoveries from currently producing horizons.

“Looking through the remainder of 2011, we are on track to meet production guidance, we expect to initiate development operations at our acquisition properties and we will drill a handful of new exploration prospects that are all directed at oil. We will be working diligently to position the Company for very strong growth in 2012.”

Second quarter 2011 natural gas and oil production totaled 26.5 billion cubic feet equivalent (“Bcfe”), up 6% from 25.1 Bcfe in the second quarter of 2010 and up 14% sequentially from the first quarter of 2011. For the first half of 2011, production totaled 49.7 Bcfe, also up 6% from the 2010 period. The Company is on-track for its full year guidance of 106 to 110 Bcfe. Production growth was predominantly from the West Tavaputs natural gas program and the Blacktail Ridge-Lake Canyon oil program, both in the Uinta Basin. Including the effects of the Company’s hedging activities and natural gas liquids recovery, the average realized sales price in the second quarter of 2011 was \$7.01 per thousand cubic feet equivalent (“Mcf”) compared with \$7.10 per Mcf in

the second quarter of 2010. The Company's commodity hedging program increased second quarter 2011 natural gas and oil revenues by net \$11.2 million, or \$0.42 per Mcfe of production.

Discretionary cash flow (a non-GAAP measure, see "Discretionary Cash Flow Reconciliation" below) in the second quarter of 2011 was \$122.8 million, or \$2.61 per diluted common share. Discretionary cash flow was up slightly compared with \$2.55 per diluted common share in the second quarter of 2010 and up 17% sequentially compared with \$2.24 per diluted common share in the first quarter of 2011. Year-over-year, the second quarter of 2011 had higher production partially offset by slightly lower realized prices and slightly higher cash operating costs. Discretionary cash flow for the first half of 2011 was \$227.5 million, up 3% from \$220.7 million in the first half of 2010.

Net income in the second quarter of 2011 was \$32.6 million, or \$0.69 per diluted common share, compared with \$39.2 million, or \$0.86 per diluted common share, in the second quarter of 2010. The lower net income was primarily due to a larger non-cash derivative gain in the 2010 quarter. Dry hole expense in the second quarter of 2011 was \$0.2 million and was related to wells determined to be dry holes in prior periods. Net income for the first half of 2011 was \$47.9 million, down 24% from the first half of 2010 primarily due to non-cash derivative gains in the 2010 period. Adjusted net income for the second quarter of 2011 (a non-GAAP measure, see "Adjusted Net Income Reconciliation" below) was \$27.6 million, or \$0.59 per diluted common share, compared with \$28.1 million, or \$0.62 per diluted common share, in the second quarter of 2010. Adjusted net income removes the effect of non-recurring charges such as unrealized derivative gains and losses, impairment expenses, property sales and one-time items.

## **DEBT AND LIQUIDITY**

At June 30, 2011, the Company's revolving credit facility had an outstanding balance of \$145.0 million, a borrowing base of \$800.0 million, total commitments of \$700.0 million and, after deducting an outstanding letter of credit for \$26.0 million, borrowing capacity of \$529.0 million. The Company expects to continue to draw from its revolving credit facility as planned capital expenditures including acquisition costs are expected to exceed cash flows from operations. The Company also had \$172.5 million in 5% convertible senior notes and \$250.0 million in 9.875% senior notes outstanding at June 30, 2011.

## **OPERATIONS**

### **Production, Wells Spud and Capital Expenditures**

The following table lists production, wells spud and total capital expenditures by basin for the three months and six months ended June 30, 2011:

Basin	Three Months ended June 30, 2011			Six Months ended June 30, 2011		
	Average Net Production (MMcfe/d)	Wells Spud (gross)	Capital Expenditures (millions)	Average Net Production (MMcfe/d)	Wells Spud (gross)	Capital Expenditures (millions)
Piceance	130	29	\$ 48.7	132	49	\$ 94.4
Uinta	108	28	213.2	90	56	279.0
Powder River (CBM)	36	3	0.4	37	5	3.5
Wind River	16	0	0.6	15	0	1.5
Other	1	10	20.3	2	12	29.6
<b>Total</b>	<b>291</b>	<b>70</b>	<b>\$ 283.2</b>	<b>275</b>	<b>122</b>	<b>\$ 408.0</b>

Capital expenditures totaled \$283.2 million for the second quarter of 2011, including the acquisition of East Bluebell in the Uinta Basin for \$119.4 million.

### Operating and Drilling Update

The Company anticipates drilling approximately 300 gross development wells in 2011, including approximately 30 coal bed methane (“CBM”) wells. The Company currently has six active drilling rigs with two at West Tavaputs, two at Gibson Gulch and two at Blacktail Ridge-Lake Canyon. The Company’s development program is focused on growth in production and reserves as well as driving operating efficiencies at West Tavaputs.

#### Uinta Basin, Utah

**West Tavaputs** – Current net production is approximately 93 million cubic feet equivalent per day (“MMcfe/d”). The Company is successfully executing its full-field development program in the area, driving rapid growth and increasingly efficient operations. The Company is on track for its approximate 100-well program in the area for 2011. West Tavaputs is the Company’s largest development asset based on its current reserve base of 345 Bcfe proved and 1.3 Tcfe proved, probable and possible reserves (see “Reserve Disclosure” below), providing a multi-year, high growth program for the Company.

At June 30, 2011, the Company had an approximate 97% working interest in production from 220 gross wells in its West Tavaputs shallow and deep programs. The West Tavaputs program’s primary development targets include the shallow Mesaverde and Wasatch zones. Upside potential is also recognized in the shallow Green River oil zones and deeper formations including the Mancos.

**Blacktail Ridge-Lake Canyon** – Current net production, including production from the East Bluebell acquisition, is approximately 3,700 Boe/d. The Company plans to add a third rig to the combined Blacktail Ridge-Lake Canyon and East Bluebell areas in September of 2011. This area offers upside potential through horizontal drilling, increased density and field extension.

During the second quarter of 2011, the Company drilled two horizontal wells into the Uteland Butte formation (working interest 56.25%). The first well was completed in the Uteland Butte at approximately 4,700’ with a 3,100’ lateral and 15 fracture stimulation stages and flowed an average 717 Boe/d over the first 30 days of production. The second well was more recently completed in the Uteland Butte at approximately 4,600’ with a 3,200’ lateral and 15 fracture stimulation stages also with positive initial rates. The Company is encouraged by these initial results and is planning up to an additional five horizontal wells targeting the Uteland Butte formation in the second half of 2011. Success in the Uteland Butte formation opens the potential

for inventory expansion at Blacktail Ridge-Lake Canyon as well as increasing the recoveries from currently producing horizons.

At June 30, 2011, the Company had an approximate 63% working interest in production from 61 gross wells. The working interests in this area range from 19% to 100%.

**East Bluebell** – During the second quarter of 2011, the Company closed on the acquisition of oil properties and related assets located approximately 35 miles east-northeast of the Company's Blacktail Ridge-Lake Canyon operations. In the transaction, the Company acquired an estimated 5 MMBoe net proved reserves, an estimated 25 MMBoe proved, probable and possible reserves, 750 Boe/d net production, associated gathering and transportation infrastructure and 20,300 net acres of mineral leasehold for a purchase price of \$119.4 million, subject to final purchase price adjustments.

#### **Piceance Basin, Colorado**

**Gibson Gulch** – Current net production is approximately 130 MMcf/d. The Company plans to operate two rigs in the area through 2011 with an approximate 100 well program. The Company continues to benefit from its election to process the majority of its Gibson Gulch natural gas production, which exposes the Company to natural gas liquids pricing. The incremental benefit to production revenues related to natural gas liquids increased to \$1.23 per Mcfe to the Company-wide realized price in the second quarter of 2011, up as a result of higher per gallon realized liquids pricing. Gibson Gulch operations offer strong margins due to low operating costs and the currently higher revenues related to liquids. The program continues to be a key, lower risk development area for the Company.

At June 30, 2011, the Company had an approximate 98% working interest in production from 765 gross wells in its Gibson Gulch program.

**Cottonwood Gulch** – The status of the Company's Cottonwood Gulch acquisition remains unchanged. In June 2009, the Company acquired a 90% working interest in 40,300 gross undeveloped acres in Cottonwood Gulch. The leases were challenged in Federal District Court by environmental groups and resolution of the case is currently pending with a District Court judge.

#### **Denver-Julesburg ("DJ") Basin, Colorado and Wyoming**

**Wattenberg/Chalk Bluffs/Sagebrush** – In July 2011, the Company announced the signing of a purchase and sale agreement to acquire properties in the DJ Basin that include a preliminary estimate of 7 MMBoe net proved reserves, approximately 650 Boe/d net production and approximately 28,000 net acres. Current production is from the Wattenberg Field from the Codell, Niobrara and J Sands formations. The purchase price is \$150 million and the transaction is expected to close during the third quarter of 2011. The Company also holds approximately 38,200 net acres in the Sagebrush area. The Company's DJ Basin exploration is targeting Niobrara oil.

#### **Wind River Basin, Wyoming**

**McRae Gap** - The Company has identified approximately 103,000 net undeveloped acres within its acreage position in the area that it considers prospective for Niobrara shale oil. In the fourth quarter of 2010, the Company drilled a horizontal exploration well into the lower bench of the Niobrara Shale at approximately 8,200 feet depth with an approximate 3,200 foot lateral and the well is currently undergoing completion operations, which were delayed due to regional wildlife stipulations.

## Paradox Basin, Colorado

**Yellow Jacket and Green Jacket** – At the Yellow Jacket shale gas prospect (100% working interest), the Company continues to produce from three wells. The Company currently is seeking a partner prior to re-starting exploration drilling in the area. The Yellow Jacket and Green Jacket prospects include approximately 469,000 gross acres and 359,000 net undeveloped acres.

## ADDITIONAL FINANCIAL INFORMATION

### Guidance

The Company's 2011 guidance (please reference "Forward-Looking Statements" below) is updated as follows:

- Capital expenditures for exploration and development of \$685 to \$705 million including additional drilling and facilities capital expenditures at the East Bluebell acquisition area and pending DJ Basin acquisition area. This amount is before acquisition purchase costs.
- Oil and natural gas production of 106 to 110 Bcfe, unchanged and inclusive of East Bluebell and the pending DJ Basin acquisitions for which the 2011 production contribution is within the guidance range.
- Lease operating costs per Mcfe of \$0.54 to \$0.58, reduced from previous guidance of \$0.56 to \$0.60 as a result of effective cost discipline across operations.
- Gathering, transportation and processing costs per Mcfe of \$0.89 to \$0.93, unchanged.
- General and administrative expenses before non-cash stock-based compensation between \$46.0 and \$47.5 million, slightly increased from between \$45 and \$47 million, partially due to additional personnel associated with acquisitions.

### Commodity Hedges Update

It is the Company's strategy to hedge a portion of its production to reduce the risks associated with unpredictable future commodity prices and to provide predictability for a portion of cash flows in order to support the Company's capital expenditure program.

For July through December 2011 and for 2012, the Company has hedges in place as outlined in the table below. Swap and collar hedge positions are tied to regional sales points and include:

- For July through December 2011, approximately 38.3 Bcfe at a weighted average blended floor price of \$7.34 per Mcfe.
- For 2012, approximately 50.5 Bcfe at a weighted average blended floor price of \$7.09 per Mcfe.

As of July 31, 2011:

### SWAPS & COLLARS

Period	Natural Gas / NGLs		Oil		EQUIVALENT	
	Volume	Price	Volume	Price	Volume	Price
	MMBtu/d	\$MMBtu	Bbl/d	\$/Bbl	MMcfe	\$/Mcfe
3Q11	214,183	\$ 6.02	3,165	\$ 93.44	19,661	\$ 7.41
4Q11	201,141	\$ 5.79	3,300	\$ 93.66	18,644	\$ 7.27
1Q12	168,131	\$ 5.05	2,900	\$ 102.52	15,492	\$ 6.74
2Q12	133,131	\$ 5.11	2,900	\$ 102.52	12,597	\$ 7.06
3Q12	133,069	\$ 5.11	2,900	\$ 102.52	12,730	\$ 7.06
4Q12	96,602	\$ 5.31	2,900	\$ 102.52	9,680	\$ 7.70

In addition, the Company has natural gas basis only hedges in place for 2011 for 20,000 MMBtu/d at a basis differential price between CIG Rocky Mountains and Henry Hub of (\$1.72) per MMBtu and for 2012 of 20,000 MMBtu/d at a basis differential price of (\$1.22) per MMBtu. These hedges are not in the money.

## **SECOND QUARTER 2011 WEBCAST AND CONFERENCE CALL**

As previously announced, a webcast and conference call will be held later this morning to discuss second quarter 2011 results. Please join Bill Barrett Corporation executive management at 12:00 p.m. Eastern time ("ET")/10:00 a.m. Mountain time ("MT") for the live webcast, accessed at [www.billbarrettcorp.com](http://www.billbarrettcorp.com), or join by telephone by calling 800-260-8140 (617-614-3672 international callers) with passcode 64733949. The webcast will remain available on the Company's website for approximately 30 days, and a replay of the call will be available through August 11, 2011 at call-in number 888-286-8010 (617-801-6888 international) with passcode 77348244. The Company also has tentatively scheduled its third quarter 2011 earnings conference call for November 3, 2011 at noon ET/10:00 a.m. MT.

## **UPCOMING EVENTS**

Updated investor presentations will be posted to the homepage of the Company's website at [www.billbarrettcorp.com](http://www.billbarrettcorp.com) for each event below. Please check the website at 5:00 p.m. MT on the business day prior to the investor event for the most recent presentation, unless otherwise noted:

### **Investor Conferences**

Chairman, Chief Executive Officer and President Fred Barrett will present at the EnerCom Oil & Gas Conference in Denver on August 18, 2011 at 8:25 a.m. MT. The event will be webcast. The presentation for this event will be posted at 5:00 p.m. MT on Monday, August 15, 2011.

Chairman, Chief Executive Officer and President Fred Barrett will present at the Barclays CEO Energy Conference in New York City on September 7, 2011 at 1:45 p.m. ET. The event will be webcast.

Chairman, Chief Executive Officer and President Fred Barrett will participate at the Deutsche Bank Energy Conference in Boston to be held September 21-22, 2011. The event is not webcast.

## **DISCLOSURE STATEMENTS**

### **Forward-Looking Statements**

This press release contains forward-looking statements, including statements regarding projected results and future events, including guidance and the upside potential and other prospects of acquisitions and other planned activities. These forward-looking statements are based on management's judgment as of this date and include certain risks and uncertainties. Please refer to the Company's Annual Report on Form 10-K for the year-ended December 31, 2010 filed with the SEC, and other filings including our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 and Current Reports on Form 8-K, for a list of certain risk factors.

Actual results may differ materially from Company projections and can be affected by a variety of factors outside the control of the Company including, among other things, the final and timely closing of the acquisition, market conditions, oil and gas price volatility, exploration and

development drilling and testing results, the ability to receive drilling and other permits and rights-of-way, regulatory approvals, governmental laws and regulations and changes in enforcement of those laws and regulations, new laws and regulations, risks related to and costs of hedging activities including counterparty viability, surface access and costs, availability of third party gathering, transportation and processing, the availability and cost of services and materials, the ability to obtain industry partners to jointly explore certain prospects and the willingness and ability of those partners to meet capital obligations when requested, availability and costs of financing to fund the Company's operations, uncertainties inherent in oil and gas production operations and estimating reserves, the speculative actual recovery of estimated potential volumes, unexpected future capital expenditures, competition, risks associated with operating in one major geographic area, the success of the Company's risk management activities, title to properties, litigation, environmental liabilities, and other factors discussed in the Company's reports filed with the SEC. Bill Barrett Corporation encourages readers to consider the risks and uncertainties associated with projections and other forward-looking statements. In addition, the Company assumes no obligation to publicly revise or update any forward-looking statements based on future events or circumstances.

### **Reserve Disclosure**

The SEC, under its recently revised guidelines, permits oil and gas companies to disclose probable and possible reserves in their filings with the SEC. The Company does not plan to include probable and possible reserve estimates in its filings with the SEC.

The Company has provided internally generated estimates for probable and possible reserves in this release. The estimates conform to SEC guidelines. They are not prepared or reviewed by third party engineers. Our probable and possible reserve estimates are determined using strip pricing, which we use internally for planning and budgeting purposes. The Company's estimate of probable and possible reserves is provided in this release because management believes it is useful, additional information that is widely used by the investment community in the valuation, comparison and analysis of companies. U.S. investors are urged to consider closely the disclosure in our Annual Report on Form 10-K for the year ended December 31, 2010, available on the Company's website at [www.billbarrettcorp.com](http://www.billbarrettcorp.com) or from the corporate offices at 1099 18th Street, Suite 2300, Denver, CO 80202. You can also obtain this form from the SEC by calling 1-800-SEC-0330 or at [www.sec.gov](http://www.sec.gov).

### **ABOUT BILL BARRETT CORPORATION**

Bill Barrett Corporation (NYSE: BBG), headquartered in Denver, Colorado, explores for and develops natural gas and oil in the Rocky Mountain region of the United States. Additional information about the Company may be found on its website [www.billbarrettcorp.com](http://www.billbarrettcorp.com).

**BILL BARRETT CORPORATION**  
**Selected Operating Highlights**  
**(Unaudited)**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
<b>Production Data:</b>				
Natural gas (MMcf)	24,506	23,342	45,941	43,965
Oil (MBbls)	331	288	628	473
Combined volumes (MMcfe)	26,492	25,070	49,709	46,803
Daily combined volumes (Mmcfe/d)	291	275	275	259
<b>Average Prices (before the effects of realized hedges):</b>				
Natural gas (per Mcf)	\$ 5.91	\$ 5.01	\$ 5.77	\$ 5.62
Oil (per Bbl)	89.40	67.27	85.52	67.65
Combined (per Mcfe)	6.59	5.44	6.41	5.96
<b>Average Realized Prices (after the effects of realized hedges):</b>				
Natural gas (per Mcf)	\$ 6.47	\$ 6.76	\$ 6.57	\$ 6.91
Oil (per Bbl)	82.40	70.18	80.53	70.12
Combined (per Mcfe)	7.01	7.10	7.09	7.20
<b>Average Costs (per Mcfe):</b>				
Lease operating expense	\$ 0.53	\$ 0.54	\$ 0.55	\$ 0.56
Gathering, transportation and processing expense	0.81	0.74	0.82	0.74
Production tax expense (1)	0.37	0.36	0.37	0.37
Depreciation, depletion and amortization	2.60	2.63	2.70	2.62
General and administrative expense, excluding non-cash stock-based compensation (2)	0.41	0.41	0.48	0.43

(1) Production tax expense for the first six months of 2010 includes a one-time benefit to reduce and re-estimate prior periods as a result of amended returns filed with the States of Utah and Colorado regarding the calculation of severance taxes. Exclusive of the one-time benefits, the production tax expense per Mcfe for the first six months of 2010 would have been \$0.42.

(2) Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of cash required for general and administrative expenses. Management also believes that this disclosure may allow for a more accurate comparison to the Company's peers that may have higher or lower costs associated with equity grants.

**BILL BARRETT CORPORATION**  
**Consolidated Statements of Operations**  
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
<b>(in thousands, except per share amounts)</b>				
<b>Operating and Other Revenues:</b>				
Oil and gas production	(1) \$ 194,328	\$ 186,300	\$ 366,525	\$ 349,949
Commodity derivative gain (loss)	(1) (2,907)	7,676	(14,019)	2,012
Other	3,021	2,649	3,259	2,474
<b>Total operating and other revenues</b>	<b>194,442</b>	<b>196,625</b>	<b>355,765</b>	<b>354,435</b>
<b>Operating Expenses:</b>				
Lease operating	14,075	13,581	27,374	26,022
Gathering, transportation and processing	21,338	18,487	40,674	34,457
Production tax	(2) 9,781	9,042	18,347	17,331
Exploration	697	654	2,048	955
Impairment, dry hole costs and abandonment	1,093	988	1,376	3,867
Depreciation, depletion and amortization	68,847	65,900	134,241	122,434
General and administrative	(3) 10,739	10,201	23,806	20,003
Non-cash stock-based compensation	(3) 4,018	3,767	8,647	7,741
<b>Total operating expenses</b>	<b>130,588</b>	<b>122,620</b>	<b>256,513</b>	<b>232,810</b>
<b>Operating Income</b>	<b>63,854</b>	<b>74,005</b>	<b>99,252</b>	<b>121,625</b>
<b>Other Income and Expense:</b>				
Interest and other income	102	105	165	125
Interest expense	(12,321)	(11,199)	(24,363)	(21,322)
<b>Total other income and expense</b>	<b>(12,219)</b>	<b>(11,094)</b>	<b>(24,198)</b>	<b>(21,197)</b>
<b>Income before Income Taxes</b>	<b>51,635</b>	<b>62,911</b>	<b>75,054</b>	<b>100,428</b>
<b>Provision for Income Taxes</b>	<b>18,999</b>	<b>23,713</b>	<b>27,203</b>	<b>37,253</b>
<b>Net Income</b>	<b>\$ 32,636</b>	<b>\$ 39,198</b>	<b>\$ 47,851</b>	<b>\$ 63,175</b>
<b>Net Income Per Common Share</b>				
Basic	\$ 0.70	\$ 0.87	\$ 1.03	\$ 1.40
Diluted	\$ 0.69	\$ 0.86	\$ 1.02	\$ 1.39
<b>Weighted Average Common Shares Outstanding</b>				
Basic	46,416	45,080	46,255	44,995
Diluted	47,108	45,521	46,929	45,456

- (1) The table below summarizes the realized and unrealized gains and losses the Company recognized related to its oil and natural gas derivative instruments for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
<b>Included in oil and gas production revenue:</b>				
Realized gain on cash flow hedges	\$ 19,776	\$ 49,889	\$ 47,699	\$ 70,898
<b>Included in commodity derivative loss:</b>				
Realized loss on derivatives not designated as cash flow hedges	\$ (8,590)	\$ (8,223)	\$ (13,994)	\$ (12,986)
Unrealized ineffectiveness gain (loss) recognized on derivatives designated as cash flow hedges	888	(659)	1,050	(266)
Unrealized gain (loss) on derivatives not designated as cash flow hedges	4,795	16,558	(1,075)	15,264
<b>Total commodity derivative gain (loss)</b>	<b>\$ (2,907)</b>	<b>\$ 7,676</b>	<b>\$ (14,019)</b>	<b>\$ 2,012</b>

- (2) Production tax expense for the first six months of 2010 period includes a one-time benefit to reduce and re-estimate prior periods as a result of amended returns filed with the States of Utah and Colorado regarding the calculation of severance taxes.
- (3) Management believes the separate presentation of the non-cash component of general and administrative expense is useful because the cash portion provides a better understanding of cash required for general and administrative expenses. Management also believes that this disclosure may allow for a more accurate comparison to the Company's peers that may have higher or lower costs associated with equity grants.

**BILL BARRETT CORPORATION**  
**Consolidated Condensed Balance Sheets**  
**(Unaudited)**

(in thousands)	As of June 30, 2011	As of December 31, 2010
<b>Assets:</b>		
Cash and cash equivalents	\$ 39,856	\$ 58,690
Other current assets (1)	132,004	148,958
Property and equipment, net	2,087,601	1,811,819
Other noncurrent assets	23,995	19,033
<b>Total assets</b>	<b>\$ 2,283,456</b>	<b>\$ 2,038,500</b>
<b>Liabilities and Stockholders' Equity:</b>		
Current liabilities (1)	\$ 182,210	\$ 165,957
Notes payable to bank	145,000	-
Senior notes	240,463	239,766
Convertible senior notes	167,704	164,633
Other long-term liabilities (1)	357,768	327,182
Stockholders' equity	1,190,311	1,140,962
<b>Total liabilities and stockholders' equity</b>	<b>\$ 2,283,456</b>	<b>\$ 2,038,500</b>

- (1) At June 30, 2011, the estimated fair value of all of our commodity derivative instruments was a net asset of \$27.7 million, comprised of: \$28.0 million current assets; \$4.0 million current liabilities; \$6.1 million non-current assets; and, \$2.4 million non-current liabilities. This amount will fluctuate quarterly based on estimated future commodity prices and the current hedge position.

**BILL BARRETT CORPORATION**  
**Consolidated Statements of Cash Flows**  
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in thousands)	2011	2010	2011	2010
<b>Operating Activities:</b>				
Net income	\$ 32,636	\$ 39,198	\$ 47,851	\$ 63,175
Adjustments to reconcile to net cash provided by operations:				
Depreciation, depletion and amortization	68,847	65,900	134,241	122,434
Impairment, dry hole costs and abandonment expenses	1,093	988	1,376	3,867
Unrealized derivative (gain) loss	(5,683)	(15,899)	25	(14,998)
Deferred income taxes	18,999	20,091	27,203	32,282
Stock compensation and other non-cash charges	5,254	4,072	10,345	8,327
Amortization of debt discounts and deferred financing costs	3,251	3,053	6,420	5,661
Gain on sale of properties	(2,288)	(1,984)	(2,009)	(1,049)
Change in assets and liabilities:				
Accounts receivable	(18,415)	1,262	(22,114)	(65)
Prepayments and other assets	(1,860)	(525)	2,069	(2,971)
Accounts payable, accrued and other liabilities	13,010	11,641	(3,314)	(3,551)
Amounts payable to oil & gas property owners	8,365	931	7,461	1,669
Production taxes payable	319	(5,737)	1,685	(2,814)
<b>Net cash provided by operating activities</b>	<b>\$ 123,528</b>	<b>\$ 122,991</b>	<b>\$ 211,239</b>	<b>\$ 211,967</b>
<b>Investing Activities:</b>				
Additions to oil and gas properties, including acquisitions	(278,630)	(108,037)	(383,802)	(199,182)
Additions of furniture, equipment and other	(2,052)	(929)	(2,772)	(1,638)
Proceeds from sale of properties and other investing activities	2,204	(837)	1,860	2,268
<b>Net cash used in investing activities</b>	<b>\$ (278,478)</b>	<b>\$ (109,803)</b>	<b>\$ (384,714)</b>	<b>\$ (198,552)</b>
<b>Financing Activities:</b>				
Proceeds from credit facility	145,000	-	145,000	20,000
Principal payments on credit facility	-	(15,000)	-	(25,000)
Deferred financing costs and other	(129)	(94)	(3,437)	(14,966)
Proceeds from stock option exercises	8,725	893	13,078	2,387
<b>Net cash provided by (used in) financing activities</b>	<b>\$ 153,596</b>	<b>\$ (14,201)</b>	<b>\$ 154,641</b>	<b>\$ (17,579)</b>
<b>Decrease in Cash and Cash Equivalents</b>	<b>(1,354)</b>	<b>(1,013)</b>	<b>(18,834)</b>	<b>(4,164)</b>
<b>Beginning Cash and Cash Equivalents</b>	<b>41,210</b>	<b>51,254</b>	<b>58,690</b>	<b>54,405</b>
<b>Ending Cash and Cash Equivalents</b>	<b>\$ 39,856</b>	<b>\$ 50,241</b>	<b>\$ 39,856</b>	<b>\$ 50,241</b>



**BILL BARRETT CORPORATION**  
**Reconciliation of Discretionary Cash Flow & Adjusted Net Income**  
(Unaudited)

**Discretionary Cash Flow Reconciliation**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
<b>(in thousands, except per share amounts)</b>				
Net Income	\$ 32,636	\$ 39,198	\$ 47,851	\$ 63,175
Adjustments to reconcile to discretionary cash flow:				
Depreciation, depletion and amortization	68,847	65,900	134,241	122,434
Impairment, dry hole and abandonment expenses	1,093	988	1,376	3,867
Exploration expense	697	654	2,048	955
Unrealized derivative (gain) loss	(5,683)	(15,899)	25	(14,998)
Deferred income taxes	18,999	20,091	27,203	32,282
Stock compensation and other non-cash charges	5,254	4,072	10,345	8,327
Amortization of debt discounts and deferred financing costs	3,251	3,053	6,420	5,661
Gain on sale of properties	(2,288)	(1,984)	(2,009)	(1,049)
Discretionary Cash Flow	\$ 122,806	\$ 116,073	\$ 227,500	\$ 220,654
Per share, diluted	\$ 2.61	\$ 2.55	\$ 4.85	\$ 4.85
Per Mcfe	\$ 4.64	\$ 4.63	\$ 4.58	\$ 4.71

**Adjusted Net Income Reconciliation**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
<b>(in thousands except per share amounts)</b>				
Net Income	\$ 32,636	\$ 39,198	\$ 47,851	\$ 63,175
Adjustments to net income:				
Unrealized derivative (gain) loss	(5,683)	(15,899)	25	(14,998)
Gain on sale of properties	(2,288)	(1,984)	(2,009)	(1,049)
One time items:				
Production tax expense	-	-	-	(2,184)
Subtotal Adjustments	(7,971)	(17,883)	(1,984)	(18,231)
Effective tax rate	37%	38%	36%	37%
Tax effected adjustments	(5,022)	(11,087)	(1,270)	(11,486)
Adjusted Net Income	\$ 27,614	\$ 28,111	\$ 46,581	\$ 51,689
Per share, diluted	\$ 0.59	\$ 0.62	\$ 0.99	\$ 1.14
Per Mcfe	\$ 1.04	\$ 1.12	\$ 0.94	\$ 1.10

The non-GAAP (Generally Accepted Accounting Principles in the United States of America) measures of discretionary cash flow and adjusted net income are presented because management believes that they provide useful additional information to investors for analysis of the Company's ability to internally generate funds for exploration, development and acquisitions as well as adjusting net income for unusual items to allow for a more consistent comparison from period to period. In addition, these measures are widely used by professional research analysts and others in the valuation, comparison and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions.

These measures should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, profitability, cash flow or liquidity measures prepared in accordance with GAAP. Because discretionary cash flow and adjusted net income exclude some, but not all, items that affect net income and net cash provided by operating activities and may vary among companies, the amounts presented may not be comparable to similarly titled measures of other companies.