Capital Product Partners L.P.
Form 6-K
February 01, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER PURSUANT TO RULE 13a-16 OR
15d-16 OF THE SECURITIES EXCHANGE ACT OF 1934

For the month of January, 2011
COMMISSION FILE NUMBER 001-33373

CAPITAL PRODUCT PARTNERS L.P.

(Translation of registrant's name into English)

3 IASSONOS STREET
PIRAEUS, 18537 GREECE
(address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F x Form 40-F o

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes o No x

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):

Yes o No x

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes o No x

If “yes” is marked, indicate below this file number assigned to the registrant in connection with Rule 12g3-2(b): N/A

Item 1 – Information Contained in this Form 6-K Report

Attached as Exhibit I is a press release of Capital Product Partners L.P., dated January 31, 2011.

This report on Form 6-K is hereby incorporated by reference into the registrant's registration statement, registration number 333-153274, dated October 1, 2008.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CAPITAL PRODUCT PARTNERS, L.P.,

By: Capital GP L.L.C., its general partner

/s/ Ioannis E. Lazaridis
Name: Ioannis E. Lazaridis
Title: Chief Executive Officer and Chief Financial Officer of Capital GP L.L.C.

Dated: January 31, 2011

Exhibit I

CAPITAL PRODUCT PARTNERS L.P. ANNOUNCES FOURTH QUARTER 2010 FINANCIAL RESULTS

ATHENS, Greece, January 31, 2011 -- Capital Product Partners L.P. (the "Partnership") (Nasdaq: CPLP), an international owner of modern double-hull tankers, today released its financial results for the fourth quarter ended December 31, 2010.

The Partnership's net income for the quarter ended December 31, 2010 was $2.4 million, or $0.06 per limited partnership unit, which is $0.04 lower than the $0.10 per unit from the previous quarter ended September 30, 2010, and $0.15 lower than the $0.21 per unit from the fourth quarter of 2009.

Operating surplus for the quarter ended December 31, 2010 was $9.0 million, which is $0.5 million lower than the $9.5 million from the third quarter of 2010 and $1.2 million lower than the $10.2 million from the fourth quarter of 2009. Operating surplus is a non-GAAP financial measure used by certain investors to measure the financial performance of the Partnership and other master limited partnerships. (Please see Appendix A for a reconciliation of this non-GAAP measure to net income.)

Revenues for the fourth quarter of 2010 were $29.0 million, compared to $32.5 million in the fourth quarter of 2009. The Partnership's revenues reflect the lower charter rates at which it re-chartered a number of its vessels whose original charters, which were fixed during 2006 to 2008, expired during the previous quarters.

Total operating expenses for the fourth quarter of 2010 were $18.5 million, including $7.9 million in fees for the commercial and technical management of the fleet paid to a subsidiary of our Sponsor, Capital Maritime & Trading Corp, $8.1 million in depreciation and $1.3 million in general and administrative expenses, of which $0.6 million was a non-cash charge related to the Omnibus Incentive Compensation Plan, compared to $18.1 million total operating expenses for the fourth quarter of 2009.

Net interest expense and finance cost for the fourth quarter of 2010 amounted to $8.1 million compared to $8.2 million for the fourth quarter of 2009.

As of December 31, 2010 the Partnership's long-term debt remained unchanged, compared to December 31, 2009 at $474.0 million, and Partners' capital stood at $239.8 million.

Market Commentary

Overall, average product tanker spot earnings for the fourth quarter continued to improve, when compared to the fourth quarter of 2009, as the world economy recovery boosted demand for oil products.

Longer period charter rates remained robust, relative to the product tanker spot market, reflecting owners' and charterers' positive expectations for product tanker demand going forward. The product tanker orderbook experienced substantial delays and cancellations, which is expected to continue into 2011. As a result, the current product tanker orderbook is considered amongst the most attractive in the shipping industry.

The Suezmax market remained soft compared to the same quarter last year, as tonnage availability in most trading areas absorbed the increased demand.

Fleet Developments

The M/T Amore Mio II (2001 Daewoo, 159,924 dwt) was fixed at a net daily charter rate of $25,000 to Capital Maritime for 12 months (+/- 30 days). The charter commenced on January 9, 2011 and the earliest expected redelivery under the charter is December 2011.

Following the rechartering of the M/T Amore Mio II, 69% of the fleet total days for 2011 are secured under period charter coverage.

Quarterly Cash Distribution

On January 21, 2011, the Board of Directors of the Partnership declared a cash distribution of $0.2325 per unit for the fourth quarter of 2010, in line with management's annual guidance. The fourth quarter 2010 distribution will be paid on February 15, 2011 to unit holders of record on February 4, 2011.

The total distributions of $1.0925 paid during 2010 qualify fully as return of capital for our U.S. based unitholders, according to our advisors.

Management Commentary

Mr. Ioannis Lazaridis, Chief Executive and Chief Financial Officer of the Partnership's General Partner commented: "We are pleased to see that 2010 marked an improvement for product tanker earnings, compared to the historical lows experienced in 2009. The continued delays and cancellations observed in product tanker deliveries, combined with the recovery in demand for oil products, bode well for the prospects of the product tanker market. In addition, we are particularly pleased that we have chartered the M/T Amore Mio II to Capital Maritime, our Sponsor, for approximately one year."

Mr. Lazaridis continued: "We will continue to closely monitor key industry factors, including changes in oil product demand, oil refinery utilization rates, the availability of shipping finance, as well as further delays and cancellations that could reduce the number of new tanker vessel deliveries, in order to assess a further market recovery for 2011 and beyond. We will continue to monitor market developments and explore further accretive acquisitions, and as a result we will revisit our annual distribution guidance."

Conference Call and Webcast

Today, January 31st 2011, at 10:00 a.m. Eastern Standard Time (U.S.), the Partnership will host an interactive conference call.

Conference Call details:

Participants should dial into the call 10 minutes before the scheduled time using the following numbers: 1(866) 819-7111 (from the US), 0(800) 953-0329 (from the UK) or + (44) 1452 542 301 (Standard International Dial-in). Please quote "Capital Product Partners."

A replay of the conference call will be available until February 6, 2011. The United States replay number is 1(866) 247-4222; from the UK 0(800) 953-1533; the standard international replay number is (+44) 1452 550 000 and the access code required for the replay is: 69648481#.

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Slides and audio webcast:

The slide presentation accompanying the conference call will be available on the Partnership's website at www.capitalpplp.com. An audio webcast of the call will also be accessible on the website. The relevant links will be found in the Investor Relations section of the website.

Forward-Looking Statements:

The statements in this press release that are not historical facts, including our expectations regarding developments in the markets, our expected charter coverage ratio for 2011 and expectations regarding our quarterly distribution may be forward-looking statements (as such term is defined in Section 21E of the Securities Exchange Act of 1934, as amended). These forward-looking statements involve risks and uncertainties that could cause the stated or forecasted results to be materially different from those anticipated. Unless required by law, we expressly disclaim any obligation to update or revise any of these forward-looking statements, whether because of future events, new information, a change in our views or expectations, to conform them to actual results or otherwise. We assume no responsibility for the accuracy and completeness of the forward-looking statements. We make no prediction or statement about the performance of our common units.

About Capital Product Partners L.P.

Capital Product Partners L.P. (Nasdaq:CPLP), a Marshall Islands master limited partnership, is an international owner of modern double-hull tankers. The Partnership owns 21 vessels, including 18 modern MR tankers, two small product tankers and one suezmax crude oil tanker. Most of its vessels are under medium- to long-term charters to BP Shipping Limited, Overseas Shipholding Group, Petrobras, Arrendadora Ocean Mexicana, S.A. de C.V. and Capital Maritime & Trading Corp.

For more information about the Partnership, please visit our website: www.capitalpplp.com.
CPLP-F
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Capital Product Partners L.P.
Unaudited Condensed Consolidated Statements of Income (Note 1)
(In thousands of United States Dollars, except number of units and earnings per unit)

	For the three-month period ended December 31,		For the years ended December 31,	
	2010	2009	2010	2009
Revenues	$24,859	$32,512	$113,562	$134,519
Revenues – related party	4,146	-	11,030	-
Total Revenues	29,005	32,512	124,592	134,519
Expenses:				
Voyage expenses	1,170	810	7,009	3,993
Vessel operating expenses - related party	7,940	8,420	30,261	30,830
Vessel operating expenses	-	499	1,034	2,204
General and administrative expenses	1,270	632	3,506	2,876
Vessel depreciation	8,116	7,697	31,464	30,685
Operating income	10,509	14,454	51,318	63,931
Other income (expense), net:				
Interest expense and finance cost	(8,331)	(8,462)	(33,259)	(32,675)
Interest and other income	212	270	860	1,460
Total other (expense), net	(8,119)	(8,192)	(32,399)	(31,215)
Net income	2,390	6,262	18,919	32,716
Less:				
Net income attributable to CMTC operations	-	(986)	(983)	(3,491)
Partnership's net income	$2,390	$5,276	$17,936	$29,225
General Partner's interest in Partnership's net income	$ 48	$ 106	$359	$584
Limited Partners' interest in Partnership's net income	$ 2,342	$ 5,170	$17,577	$28,641
Net income per unit:				
Common units (basic and diluted)	0.06	0.21	0.54	1.15
Subordinated units (basic and diluted)	-	-	-	1.17
Total units (basic and diluted)	0.06	0.21	0.54	1.15
Weighted-average units outstanding:				
Common units (basic and diluted)	37,150,983			9

Net cash provided by financing activities	139,136	64,493
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(4,543)	17,828
CASH AND CASH EQUIVALENTS, beginning of period	28,112	4,128
CASH AND CASH EQUIVALENTS, end of period	$ 23,569	$ 21,956

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc. is a Houston-based independent energy company which, together with its subsidiaries (collectively, the Company), is actively engaged in the exploration, development, and production of oil and gas in the United States and United Kingdom. Our current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Niobrara Formation in Colorado, the Barnett Shale in North Texas, the Marcellus Shale in Pennsylvania, New York and West Virginia, the Utica Shale in Ohio and Pennsylvania, and the U.K. North Sea where our Huntington Field development project is currently under development.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances and are presented in accordance with U.S. generally accepted accounting principles (GAAP). The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and limited liability companies where the Company, as a partner or member, has undivided interests in the oil and gas properties. The consolidated financial statements reflect all necessary adjustments, all of which were of a normal recurring nature and are in the opinion of management necessary for a fair presentation of the Company s interim financial position, results of operations and cash flows. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC). The operating results for the three months ended March 31, 2012 are not necessarily indicative of the results to be expected for the full year. The consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2011.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, shareholders equity, net income, or net cash provided by/used in operating, investing or financing activities.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates. The Company evaluates subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves which are used in calculating the amortization of proved oil and gas property costs, the present value of future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and asset retirement obligations. Other significant estimates include the impairment of unproved properties, fair values of derivative instruments, stock-based compensation, the collectability of outstanding receivables, and contingencies. Proved oil and gas reserve estimates have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality and quantity of available data and the application of engineering and geological interpretation and judgment to available data. Subsequent drilling results, testing and production may justify revisions of such estimates. Accordingly, proved oil and gas reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. In addition, proved oil and gas reserve estimates are vulnerable to changes in average market prices of oil and gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

Estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices of oil and gas, the creditworthiness of counterparties, interest rates and the market value and volatility of the Company s common stock. Future changes in these assumptions may affect these significant estimates materially in the near term.

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Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with original maturities of three months or less.

Accounts Receivable and Allowance for Doubtful Accounts

The Company establishes an allowance for doubtful accounts when it determines that it will not collect all or a part of an accounts receivable balance. The Company assesses the collectability of its accounts receivable on a quarterly basis and adjusts the allowance as necessary using the specific identification method. At each of March 31, 2012 and December 31, 2011, the Company s allowance for doubtful accounts was $2.3 million.

Concentration of Credit Risk

Substantially all of the Company s accounts receivable result from oil and gas sales, joint interest billings to third parties in the oil and gas industry or drilling and completion advances to third-party operators for development costs of wells in progress. This concentration of customers and joint interest owners may impact the Company s overall credit risk in that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not require collateral from its customers. The Company generally has the right to offset revenue against related billings to joint interest owners.

Derivative instruments subject the Company to a concentration of credit risk. See Note 8. Derivative Instruments for further discussion of concentration of credit risk related to the Company s derivative instruments.

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to costs centers established on a country-by-country basis. Internal costs directly associated with acquisition, exploration and development activities are capitalized and totaled $4.1 million and $3.0 million for the three months ended March 31, 2012 and 2011, respectively. Costs related to production, general corporate overhead and similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting oil and natural gas liquids to gas equivalents at the ratio of one barrel of oil or natural gas liquids to six thousand cubic feet of gas, which represents their approximate relative energy content. The equivalent unit-of-production rate is computed on a quarterly basis by dividing production by proved oil and gas reserves at the beginning of the quarter then applying such amount to capitalized oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Average depreciation, depletion and amortization (DD&A) per Mcfe on oil and gas properties was $2.24 and $1.53 for the three months ended March 31, 2012 and 2011, respectively.

Costs not subject to amortization include unevaluated leasehold costs, seismic costs associated with specific unevaluated properties, related capitalized interest and the cost of exploratory wells in progress. Significant costs are assessed individually on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs are added to the oil and gas property costs subject to amortization. Factors the Company considers in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production and drilling capital expenditure plans. The Company expects to complete its evaluation of the majority of its unproved properties within the next two to five years. Insignificant costs are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease term of the properties. The Company capitalized interest costs associated with its unevaluated leasehold and seismic costs of $6.0 million and $5.3 million for the three months ended March 31, 2012 and 2011, respectively. Interest is capitalized on the average balance of unproved properties using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of oil and gas properties are recognized as a reduction of capitalized oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Company has not had any sales of oil and gas properties that significantly alter that relationship.

In connection with the formation of ACP II Marcellus LLC (ACP II), the Company s partner in one of its joint ventures in the Marcellus Shale, the Company was issued a class of interests (B Units) in ACP II. The B Units entitle the Company to certain percentages of cash distributions to affiliates of Avista Capital Partners, LP, (together with its affiliates, Avista), if, when and only to the extent that those cash distributions exceed certain internal rates-of-return and return-on-investment thresholds with respect to

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Avista s investment in ACP II as set forth in the limited liability company agreement of ACP II. Because the B Units do not provide the Company with an ownership interest in the oil and gas properties of ACP II, the Company is not required to pay for property acquisition, exploration or development costs associated with ACP II s ownership interest in oil and gas properties, nor do the B Units entitle the Company to recognize oil and gas production and therefore, proved reserves associated with ACP II s ownership interest in oil and gas properties. However, under the full cost method of accounting, cash distributions received on the B Units are considered proceeds from the sale of oil and gas properties which are recognized as a reduction of capitalized oil and gas property costs.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to the cost center ceiling equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of properties not subject to amortization, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period.

The estimated future net revenues used in the ceiling test are calculated using average quoted market prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period. Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices used in the ceiling test computation do not include the impact of derivative instruments because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment.

Depreciation of other property and equipment is recognized using the straight-line method based on estimated useful lives ranging from five to ten years.

Deferred Financing Costs

Deferred financing costs include legal fees, accounting fees, underwriting fees, printing costs, and other direct costs associated with revolving credit facilities or the issuance of debt instruments. The capitalized costs are amortized to interest expense using the effective interest method over the terms of the debt instruments or revolving credit facilities.

Investment

The Company accounts for its investment in Oxane Materials, Inc. (Oxane) using the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from Oxane.

Financial Instruments

The Company s financial instruments consist of cash and cash equivalents, receivables, payables, derivative instruments and long-term debt. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of derivative instruments are based on a third-party pricing model which utilizes inputs that include (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The carrying amounts of long-term debt under the Company s U.S. senior secured revolving credit facility and the Huntington Facility (as defined in Note 5. Debt below) approximate fair value as these borrowings bear interest at variable rates of interest. The carrying amounts of the Company s 8.625% Senior Notes due 2018, or the Senior Notes, and its 4.375% Convertible Senior Notes due 2028, or the Convertible Senior Notes, may not approximate fair value because the notes bear interest at fixed rates of interest. See Note 5. Debt and Note 9. Fair Value Measurements.

Asset Retirement Obligations

The Company s oil and gas properties require expenditures to plug and abandon wells after the reserves have been depleted. The asset retirement obligation is recognized when the well is drilled with an associated increase in oil and gas property costs. The asset retirement obligation is recorded at fair value and requires estimates of the costs to plug and abandon wells, the costs to restore the surface, the remaining lives of wells based on oil and gas reserve estimates and future inflation rates. The obligation is discounted using a credit-adjusted risk-free interest rate which is accreted over time to its expected settlement value. Estimated costs consider historical experience, third party estimates and state regulatory requirements and do not consider salvage values. At least annually, the Company reassesses its asset retirement obligations to determine whether a change in the estimated obligation is necessary. On an interim basis, the Company reassesses the estimated cash flows underlying the obligation when indicators suggest the estimated cash flows underlying the obligation have materially changed.

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Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) the amount of such loss is reasonably estimable.

Revenue Recognition

Oil and gas revenues are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is reasonably assured. The Company follows the sales method of accounting for oil and gas revenues whereby revenue is recognized for all oil and gas sold to purchasers, regardless of whether the sales are proportionate to the Company s ownership interest in the property. Production imbalances are recognized as an asset or liability to the extent that the Company has an imbalance on a specific property that is in excess of its remaining proved oil and gas reserves. Oil and gas sales volumes are not significantly different from the Company s share of production, and as of March 31, 2012 and December 31, 2011, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps, to manage commodity price risk associated with a portion of its forecasted oil and gas production. Derivative instruments are recognized at their balance sheet date fair value as assets or liabilities in the consolidated balance sheets. Although the derivative instruments provide an economic hedge of the Company s exposure to commodity price risk associated with a portion of its forecasted oil and gas production, because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, unrealized gains and losses as a result of changes in the fair value of derivative instruments are recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations. Realized gains and losses as a result of cash settlements with counterparties to the Company s derivative instruments are also recorded as gain (loss) on derivative instruments, net in the consolidated statements of operations. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty and subject to master netting agreements.

The Company s Board of Directors establishes risk management policies and reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with approved counterparties identify the President and Chief Financial Officer as the only Company representatives authorized to execute trades. See Note 8. Derivative Instruments for further discussion of the Company s derivative instruments.

Stock-Based Compensation

The Company grants stock options, stock appreciation rights (SARs) that may be settled in cash or common stock at the option of the Company (Stock SARs), SARs that may only be settled in cash (Cash SARs), restricted stock awards and restricted stock units to directors, employees and independent contractors. The Company recognized the following stock-based compensation expense for the periods indicated which is reflected as general and administrative expense in the consolidated statements of operations:

	Three Months Ended March 31,	
	2012	**2011**
	(In thousands)	
Stock Options and SARs	$ 1,666	$ 2,000
Restricted Stock Awards and Units	3,104	3,119
	4,770	5,119
Less: amounts capitalized	(754)	(1,269)
Total Stock-Based Compensation Expense	$ 4,016	$ 3,850
Income Tax Benefit	$ 1,474	$ 1,413

Stock Options and SARs. For stock options and Stock SARs that the Company expects to settle in common stock, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally three years). For Cash SARs and any Stock SARs that the Company expects to settle in cash, stock-based compensation expense is based on the fair value remeasured at each reporting period, recognized over the vesting period (generally three years) and classified as other accrued liabilities for the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder classified

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as other long-term liabilities. Subsequent to vesting, the liability for any SARs that the Company expects to settle in cash is remeasured in earnings at each reporting period based on fair value until the awards are settled. The Company recognizes stock-based compensation expense over the vesting period for stock options and SARs using the straight-line method, except for awards with performance conditions, in which case the Company uses the graded vesting method. Stock options typically expire ten years after the date of grant. SARs typically expire between four and seven years after the date of grant. The Company uses the Black-Scholes-Merton option pricing model to compute the fair value of stock options and SARs.

Restricted Stock Awards and Units. For restricted stock awards and units, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally one to three years) using the straight-line method, except for units with performance conditions, in which case the Company uses the graded vesting method. The fair value of restricted stock awards and units is based on the average of the high and low price of the Company s common stock on the grant date. For restricted stock awards and units granted to independent contractors, stock-based compensation expense is based on fair value remeasured at each reporting period and recognized over the vesting period (generally three years) using the straight-line method.

Foreign Currency

The U.S. dollar is the functional currency for the Company s operations in the U.K. North Sea. Transaction gains or losses that occur due to the realization of assets and the settlement of liabilities using a currency denominated in other than the functional currency are recorded as other income (expense), net in the consolidated statements of operations.

Income Taxes

Deferred income taxes are recognized at each reporting period for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. The Company routinely assesses the realizability of its deferred tax assets and considers its estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments by taxing jurisdiction. If the Company concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. The Company classifies interest and penalties associated with income taxes as interest expense.

Net Income Per Common Share

Supplemental net income per common share information is provided below:

	Three Months Ended March 31,	
	2012	**2011**
	(In thousands, except per share amounts)	
Net income	$ 9,423	$ 735
Basic weighted average common shares outstanding	39,445	38,783
Effect of dilutive instruments	472	623
Diluted weighted average common shares outstanding	39,917	39,406
Net income per common share		
Basic	$ 0.24	$ 0.02
Diluted	$ 0.24	$ 0.02

Basic net income per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the period which include restricted stock awards and units, stock options, warrants and convertible debt. Shares of common stock subject to issuance upon the conversion of the Convertible Senior Notes did not have an effect on the calculation of dilutive shares for the three months ended March 31, 2012 or 2011, because the conversion price was in excess of the market price of the common stock for those periods.

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3. PROPERTY AND EQUIPMENT, NET

At March 31, 2012 and December 31, 2011, property and equipment consisted of the following:

	March 31, 2012	December 31, 2011
	(In thousands)	
Proved oil and gas properties	$ 1,496,489	$ 1,305,084
Accumulated depreciation, depletion and amortization	(428,848)	(397,737)
Proved oil and gas properties, net	1,067,641	907,347
Costs not subject to amortization		
Unevaluated leasehold and seismic costs	291,424	277,425
Capitalized interest	50,998	46,471
Exploratory wells in progress	64,447	70,533
Total costs not subject to amortization	406,869	394,429
Other property and equipment	15,235	12,835
Accumulated depreciation	(4,426)	(4,097)
Other property and equipment, net	10,809	8,738
Total property and equipment, net	$ 1,485,319	$ 1,310,514

Sale of Barnett Shale Properties

On April 30, 2012, the Company sold a substantial portion of its Barnett Shale properties to an affiliate of Atlas Resource Partners, L.P and received net proceeds of approximately $187 million, subject to final post-closing adjustments. Proceeds from the sale will be recognized as a reduction of proved oil and gas properties, net.

4. INCOME TAXES

The Company s estimated annual effective income tax rates are used to allocate expected annual income tax expense to interim periods. The rates are the ratio of estimated annual income tax expense to estimated annual income before income taxes by taxing jurisdiction, except for discrete items, which are significant, unusual or infrequent items for which income taxes are computed and recorded in the interim period in which the specific transaction occurs. The estimated annual effective income tax rates is applied to the year-to-date income before income taxes by taxing jurisdiction to determine the income tax expense allocated to the interim period. The Company updates its estimated annual effective income tax rate at the end of each quarterly period considering the geographic mix of income based on the tax jurisdictions in which the Company operates. Actual results that are different from the assumptions used in estimating the annual effective income tax rate will impact future income tax expense. Income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate income tax rate of 35% to income before income taxes as follows:

	Three Months Ended March 31,	
	2012	2011
	(In thousands)	
Income tax expense at the statutory rate	$ 4,704	$ 628
State income taxes, net of U.S. federal income tax benefit	222	1,575
U.K. income tax benefit	(1,216)	

Capital loss associated with investment in Pinnacle for which no income tax benefit was recognized in prior years		(1,135)
Other, net	308	(8)
Income tax expense	$ 4,018	$ 1,060

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As of March 31, 2012, the Company had U.S. and U.K. income tax loss carryforwards of approximately $153.7 million and $92.9 million, respectively. The U.S. loss carryforwards expire between 2019 and 2032 if not utilized in earlier periods. The U.K. loss carryforwards are not subject to expiration as long as the Company maintains an activity trading status in the U.K. The realization of the deferred tax assets related to the loss carryforwards is dependent on the Company s ability to generate sufficient future taxable income, which the Company expects to be able to generate within the applicable carryforward periods. Accordingly, the Company believes that it is more likely than not that its net deferred tax assets will be fully realized.

At March 31, 2012, the Company had no material uncertain tax positions and the tax years since 1999 remain open to review by federal and various state tax jurisdictions.

5. DEBT

Debt consisted of the following at March 31, 2012 and December 31, 2011:

	March 31, 2012	December 31, 2011
	(In thousands)	
Senior Notes	$ 600,000	$ 600,000
Unamortized discount for Senior Notes	(5,316)	(5,464)
Convertible Senior Notes	73,750	73,750
Unamortized discount for Convertible Senior Notes	(3,132)	(3,799)
Senior Secured Revolving Credit Facility	177,000	47,000
Senior Secured Multicurrency Credit Facility	28,029	17,813
	$ 870,331	$ 729,300

Senior Notes

In connection with the issuance of an additional $200 million aggregate principal amount of unregistered Senior Notes that were issued pursuant to a private placement on November 17, 2011, on February 22, 2012, the Company completed the exchange of registered Senior Notes for all of such unregistered Senior Notes.

Senior Secured Revolving Credit Facility

The Company is party to a senior secured revolving credit facility with Wells Fargo Bank, National Association as the administrative agent. The revolving credit facility provides for a borrowing capacity up to the lesser of (i) the borrowing base (as defined in the senior credit agreement governing the revolving credit facility) and (ii) $750 million. The revolving credit facility matures on January 27, 2016. It is secured by substantially all of the Company s U.S. assets and is guaranteed by certain of the Company s U.S. subsidiaries. The initial borrowing base under the revolving credit facility was $350 million and as of March 31, 2012, the borrowing base was $340 million. As a result of the Spring 2012 borrowing base redetermination, which was effective April 30, 2012, the borrowing base was reduced to $325 million after giving effect to the removal of properties in connection with the recent sale of Barnett Shale properties, largely offset by the addition of proved reserves as a result of the Company s successful ongoing drilling program.

On March 26, 2012, the revolving credit facility was amended to, among other things, (1) extend by two quarters the dates on which the maximum ratio of Total Debt to EBITDA (each as defined in the credit agreement governing the revolving credit facility) steps down and (2) increase the basket available for redemptions of our Convertible Senior Notes.

The Company is subject to certain covenants under the terms of the revolving credit facility which include the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than (a) 4.75 to 1.00 for fiscal quarters ending March 31, 2012 and June 30, 2012, (b) 4.25 to 1.00 for fiscal quarters ending September 30, 2012 and December 31, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending March 31, 2013 and thereafter; (2) a Current Ratio of not less than 1.00 to 1.00; (3) a ratio of Senior Debt to EBITDA of not more than 2.50 to 1.00; and (4) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the credit agreement governing the revolving credit facility). At March 31, 2012, the ratio of Total

Debt to EBITDA was 4.08 to 1.00, the Current Ratio was 1.00 to 1.00, the ratio of Senior Debt to EBITDA was 0.76 to 1.00 and the ratio of EBITDA to Interest Expense was 4.91 to 1.00. Because the calculation of the financial ratios are made as of a certain date, the financial ratios can fluctuate significantly period to period as the amounts outstanding under the revolving credit facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings.

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At March 31, 2012, the Company had $177.0 million of borrowings outstanding under the revolving credit facility with a weighted average interest rate of 3.08%. At March 31, 2012, the Company also had $1.0 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. Future availability under the $325 million borrowing base is subject to the terms and covenants of the revolving credit facility. The revolving credit facility is used to fund ongoing working capital needs and the remainder of the Company s capital expenditure plan to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

U.K. Huntington Field Development Project Credit Facility

The Company and Carrizo U.K. Huntington Ltd. (Carrizo UK), as borrower, are parties to a Senior Secured Multicurrency Credit Facility (the Huntington Facility). The Huntington Facility provides for a multicurrency credit facility consisting of (1) a $55 million term loan facility to be used to fund Carrizo UK s share of project development costs, (2) a $6.5 million contingent cost overrun term loan facility and (3) a $22.5 million post-completion credit facility providing for loans and letters of credit to be used to fund certain abandonment and decommissioning costs following project completion. The availability under the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field project. An amendment to the facility was executed on April 17, 2012 which adjusted the repayment of the amounts outstanding under the term loan or cost overrun facility to the following: (i) 45% will be due on June 30, 2013, (ii) 20% will be due on December 31, 2013, (iii) 20% will be due on June 30, 2014, and (iv) the remaining 15% will be due on the final maturity date of December 31, 2014 and accordingly, the amounts outstanding under the Huntington Facility have been presented as long-term on the balance sheet. As of April 1, 2012, following the semi-annual redetermination, the term loan facility and cost overrun facility were $55 million and $6.5 million, respectively.

As of March 31, 2012, borrowings outstanding under the Huntington Facility were £17.5 million, with a weighted average interest rate of 4.58% and no letters of credit had been issued. The British Pound denominated borrowings were translated to $28.0 million at March 31, 2012, resulting in a $0.9 million transaction loss recorded in Other income (expense), net in the consolidated statements of operations.

6. COMMITMENTS AND CONTINGENCIES

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a material adverse effect on the financial position or results of operations of the Company.

The financial position and results of operations of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on oil and gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

7. SHAREHOLDERS EQUITY

On November 24, 2009, the Company entered into a Land Agreement, as amended (the Land Agreement), with an unrelated third party and its affiliate. The Land Agreement expired pursuant to its terms on May 31, 2011. Under the Land Agreement, the Company was able to acquire up to $20.0 million of oil, gas and mineral interests/leases in certain specified areas in the Barnett Shale from such third party. In consideration for the Company s receipt of an option to purchase the leases acquired by the third party, each time the third party purchased a lease group under the Land Agreement the Company agreed to issue to the third party s affiliate warrants to purchase a number of shares of the Company s common stock with an exercise price of $22.09 and an expiration date of August 21, 2017. In addition, the Company agreed that under certain circumstances where the Company reached surface casing point on an initial well in one of the areas covered by the Land Agreement but has not achieved a specified lease up threshold for acreage in such area, the Company will issue additional warrants. The warrants are subject to antidilution adjustments and may be exercised on a cashless basis.

In January 2012, the Company issued additional warrants to purchase 6,983 shares, respectively of the Company s common stock to the third party s affiliate for leases acquired prior to the expiration of the Land Agreement.

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8. DERIVATIVE INSTRUMENTS

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in its forward cash flows supporting its capital expenditure program. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. The Company s current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at March 31, 2012, and December 31, 2011 was a net asset of $29.8 million and $37.3 million, respectively. At March 31, 2012, approximately 68% of the net fair value of the Company s derivative instruments were with Credit Suisse, 13% were with BNP Paribas, 10% were with Societe Generale, 4% were with Shell Energy North America (US) LP, 3% were with Credit Agricole, and 2% were with BBVA Compass, and master netting agreements are in place with each of these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, the Company believes it has minimal credit risk and accordingly does not currently require its counterparties to post collateral to support the asset positions of its derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the financial viability of its counterparties. Because Credit Suisse, BNP Paribas, Credit Agricole, BBVA Compass, and Societe Generale are lenders in the Company s revolving credit facility, and BNP Paribas and Societe Generale are lenders in the Company s Huntington Facility, the Company is not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties as the contracts are secured by the revolving credit facility or the Huntington Facility.

The following sets forth a summary of the Company s U.S. natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of March 31, 2012:

Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2012	13,847,000	$ 5.32	$ 5.45
2013	10,950,000	$ 5.07	$ 5.07

In connection with the natural gas derivative instruments above, the Company has entered into protective put spreads. For the remainder of 2012, at market prices below the short put price of $4.62, the floor price becomes the market price plus the put spread of $1.20 on 5,661,400 of the 13,847,000 MMBtus and the remaining 8,185,600 MMBtus would have a floor price of $5.32.

Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2012	5,661,400	$ 4.62	$ 1.20

The following sets forth a summary of the Company s U.S. crude oil derivative positions at average NYMEX prices as of March 31, 2012:

Period	Volume (in Bbls)	Weighted Average Floor Price ($/Bbls)	Weighted Average Ceiling Price ($/Bbls)
2012	1,320,000	$ 86.15	$ 105.91
2013	1,679,000	$ 87.83	$ 106.94
2014	730,000	$ 92.63	$ 101.33
2015	365,000	$ 94.75	$ 94.75

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For the three months ended March 31, 2012 and 2011, the Company recorded the following related to its oil and gas derivative instruments:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(In thousands)	
Realized gain (loss) on derivative instruments, net	$ 11,133	$ 10,007
Unrealized gain (loss) on derivative instruments, net	(8,095)	(10,194)
Gain (loss) on derivative instruments, net	$ 3,038	$ (187)

9. FAIR VALUE MEASUREMENTS

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company s assets and liabilities measured at fair value on a recurring basis as of March 31, 2012 and December 31, 2011, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	March 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(In thousands)							
Assets:								
Derivative instruments	$	$ 63,497	$	$ 63,497	$	$ 61,073	$	$ 61,073
Liabilities:								
Derivative instruments		(33,732)		(33,732)		(23,792)		(23,792)
Total	$	$ 29,765	$	$ 29,765	$	$ 37,281	$	$ 37,281

The fair values of derivative instruments are based on a third-party pricing model which utilizes inputs that include (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The estimates of fair value are compared to the values provided by the counterparty for reasonableness. Derivative instruments are subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of the Company s derivative instruments, but to date has not had a material impact on estimates of fair values. The fair values reported in the consolidated balance sheets are as of a particular point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. The assets and liabilities for derivative instruments included in the tables above are presented on a gross basis. The assets and liabilities for derivative instruments included in the consolidated balance sheets are presented on a net basis when such amounts are with the same counterparty and subject to master netting agreements. The Company had no transfers in or out of Levels 1 or 2 for the three months ended March 31, 2012 or 2011.

Fair Value of Other Financial Instruments

The Company s other financial instruments consist of cash and cash equivalents, receivables, payables and long-term debt. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term

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nature of these instruments. The carrying amounts of long-term debt under the revolving credit facility and the Huntington Facility (as defined in Note 5. Debt) approximate fair value as these borrowings bear interest at variable rates of interest. The fair values of the Convertible Senior Notes and Senior Notes at March 31, 2012, were estimated at approximately $73.1 million and $628.0 million, respectively, based on quoted market prices.

Other Fair Value Measurements

The initial measurement of asset retirement obligations at fair value is calculated using discounted future cash flows of internally estimated costs. Significant Level 3 inputs used in the calculation of asset retirement obligations include the costs of plugging and abandoning wells, surface restoration and reserve lives.

10. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In November 2010 and November 2011, the Company and certain of the Company s wholly owned subsidiaries (such subsidiaries collectively, the Subsidiary Guarantors) issued in private placements $400.0 million and $200.0 million, respectively, aggregate principal amount of the Company s Senior Notes. Certain, but not all, of the Company s wholly owned subsidiaries have issued full, unconditional and joint and several guarantees of the Senior Notes and may guarantee future issuances of debt securities. In connection with both offerings, the Company subsequently filed Form S-4 Registration Statements with the SEC to exchange the previously issued privately placed notes for notes registered under the Securities Act of 1933, as amended.

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information as of March 31, 2012 and December 31, 2011, and for the three months ended March 31, 2012 and 2011 on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the Subsidiary Guarantors operated as independent entities.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are therefore reflected in the parent company s investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity. The Company s oil and gas properties are accounted for using the full cost method of accounting whereby impairments and DD&A are calculated and recorded on a country by country basis. However, when calculated separately on a legal entity basis, the combined totals of parent company and subsidiary impairments and DD&A can be more or less than the consolidated total as a result of differences in the properties each entity owns including amounts of costs incurred, production rates, reserve mix, future development costs, etc. Accordingly, elimination entries are required to eliminate any differences between consolidated and parent company and subsidiary company combined impairments and DD&A.

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CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	March 31, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
ASSETS					
Current assets	$ 1,482,390	$ 95,939	$ 2,047	$ (1,448,086)	$ 132,290
Property and equipment, net	129,459	1,266,215	81,841	7,804	1,485,319
Investments in subsidiaries	(41,003)			41,003	
Other assets	27,634	45,767	10,149	(1,630)	81,920
Total assets	$ 1,598,480	$ 1,407,921	$ 94,037	$ (1,400,909)	$ 1,699,529
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities	$ 172,047	$ 1,504,038	$ 3,754	$ (1,392,387)	$ 287,452
Long-term liabilities	853,824	2,362	32,805		888,991
Shareholders equity	572,609	(98,479)	57,478	(8,522)	523,086
Total liabilities and shareholders equity	$ 1,598,480	$ 1,407,921	$ 94,037	$ (1,400,909)	$ 1,699,529

	December 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
ASSETS					
Current assets	$ 1,349,841	$ 71,018	$ 3,874	$ (1,304,336)	$ 120,397
Property and equipment, net	101,015	1,131,672	68,911	8,916	1,310,514
Investments in subsidiaries	(58,764)			58,764	
Other assets	38,853	54,062	9,133	(5,279)	96,769
Total assets	$ 1,430,945	$ 1,256,752	$ 81,918	$ (1,241,935)	$ 1,527,680
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities	$ 150,793	$ 1,368,456	$ 4,366	$ (1,252,295)	$ 271,320
Long-term liabilities	724,801	2,183	22,429	(2,908)	746,505
Shareholders equity	555,351	(113,887)	55,123	13,268	509,855
Total liabilities and shareholders equity	$ 1,430,945	$ 1,256,752	$ 81,918	$ (1,241,935)	$ 1,527,680

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CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For the Three Months Ended March 31, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
Oil and gas revenues	$ 6,789	$ 73,926	$	$	$ 80,715
Cost and expenses	14,547	42,678	78	1,111	58,414
Operating income (loss)	(7,758)	31,248	(78)	(1,111)	22,301
Other income and (expense), net	1,127	(7,546)	(2,441)		(8,860)
Income (loss) before income taxes	(6,631)	23,702	(2,519)	(1,111)	13,441
Income tax (expense) benefit	2,321	(8,296)	1,216	741	(4,018)
Equity in income (loss) of subsidiaries	14,103			(14,103)	
Net income (loss)	$ 9,793	$ 15,406	$ (1,303)	$ (14,473)	$ 9,423

	For the Three Months Ended March 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
Oil and gas revenues	$ 8,775	$ 35,283	$	$	$ 44,058
Cost and expenses	16,181	19,410		(1,298)	34,293
Operating income (loss)	(7,406)	15,873		1,298	9,765
Other income and (expense), net	(4,144)	(3,826)			(7,970)
Income before income taxes	(11,550)	12,047		1,298	1,795
Income tax (expense) benefit	3,843	(4,426)		(477)	(1,060)
Equity in income (loss) of subsidiaries	7,621			(7,621)	
Net income (loss)	$ (86)	$ 7,621	$	$ (6,800)	$ 735

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CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Three Months Ended March 31, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Net cash provided by operating activities	$ 31,279	$ 53,607	$ (1,644)	$	$ 83,242
Net cash used in investing activities	(189,383)	(178,270)	(13,474)	154,206	(226,921)
Net cash provided by financing activities	139,137	140,091	14,114	(154,206)	139,136
Net increase (decrease) in cash and cash equivalents	(18,967)	15,428	(1,004)		(4,543)
Cash and cash equivalents, beginning of period	19,134	7,263	1,715		28,112
Cash and cash equivalents, end of period	$ 167	$ 22,691	$ 711	$	$ 23,569

	For the Three Months Ended March 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Net cash provided by operating activities	$ 28,724	$ 23,553	$	$	$ 52,277
Net cash used in investing activities	(90,639)	(77,001)	(6,469)	75,167	(98,942)
Net cash provided by financing activities	64,493	53,092	22,075	(75,167)	64,493
Net increase (decrease) in cash and cash equivalents	2,578	(356)	15,606		17,828
Cash and cash equivalents, beginning of period	1,418	2,710			4,128
Cash and cash equivalents, end of period	$ 3,996	$ 2,354	$ 15,606	$	$ 21,956

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following is management s discussion and analysis of the significant factors that affected the Company s financial position and results of operations during the periods included in the accompanying unaudited consolidated financial statements. You should read this in conjunction with the discussion under Management s Discussion and Analysis of Financial Condition and Results of Operations and the audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2011, and the unaudited consolidated financial statements included in this quarterly report.

General Overview

Our first quarter 2012 included oil and gas revenues of $80.7 million and production of 13.9 Bcfe. The key drivers to our results for the three months ended March 31, 2012 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the three months ended March 31, 2012, we drilled (a) 15 gross wells (11.6 net) in the Eagle Ford Shale, (b) 11 gross wells (3.2 net) in the Marcellus Shale, (c) 7 gross wells (3.4 net) in the Niobrara Formation, and (d) 1 gross well (0.2 net) in the U.K. North Sea.

Production. Our first quarter 2012 production of 13.9 Bcfe, or 152.4 MMcfe/d, increased 30% from the first quarter 2011 production of 10.7 Bcfe, or 118.8 MMcfe/d. The increase in production from the first quarter of 2011 to the first quarter of 2012 was primarily due to increased production from new wells, partially offset by normal production decline and the sale of substantially all of our non-core area Barnett Shale properties to KKR Natural Resources (KKR) in May 2011.

Commodity prices. Our average natural gas price during the first quarter of 2012 was $1.86 per Mcf, $1.20 per Mcf, or 39% lower than the price during the first quarter of 2011. Our average oil price during the first quarter of 2012 was $109.74 per barrel, $21.09 per barrel, or 24% higher than the price during the first quarter of 2011.

Outlook

While the market for natural gas remains challenging due to low spot and future prices, we are insulated from a portion of their effect by our hedging of 13,847,000 MMbtus of natural gas at March 31, 2012 for the remainder of 2012. We are rapidly growing our oil production, part of the effect of which will serve to further reduce our exposure to the weak natural gas market. The current market and outlook for oil and natural gas liquids sales is much more attractive and we are aggressively locking in these prices by increasing our hedge positions as our oil production grows. At March 31, 2012, we had hedges in place for 1,320,000 bbls of oil for the remainder of 2012. Production growth and commodity prices that permit us to drill, develop and produce at a profit are key to our future success.

Eagle Ford and Niobrara. Based upon the success of our drilling results since late 2010, we continue to focus on developing our liquid rich resource plays in the Eagle Ford Shale and the Niobrara Formation and have reallocated capital from development of Barnett Shale and Marcellus Shale gas to Eagle Ford and Niobrara oil. In the first quarter, we had 34 wells producing in Eagle Ford Shale and 13 wells producing in the Niobrara Formation. As of April 30, 2012, we were operating four rigs on our Eagle Ford properties and will decrease to three operated rigs in June. We continue to evaluate seismic data in the Niobrara Formation to enhance our drilling opportunities and currently have one rig drilling on our Niobrara properties.

Marcellus Shale. As a result of the material decline in natural gas prices, we and our joint venture partners are carefully reviewing our drilling program and have significantly reduced our planned spending in the Marcellus Shale during 2012. We will continue to monitor prices and, consistent with our existing contractual commitments, may decrease our activity level and capital expenditures further, or may increase such activity, if natural gas prices so warrant. In New York, we are currently evaluating a portion of our prospective Marcellus Shale acreage for Trenton-Black River prospects. As of April 30, 2012 we were operating three rigs with plans to decrease to two rigs before the end of the year.

Barnett Shale. During the first quarter we completed the remaining inventory of seven drilled but not yet completed wells which we operate and expect to participate in the drilling of one to two wells throughout the remainder of 2012.

On April 30, 2012, we completed the sale of a substantial portion of our Barnett Shale properties to an affiliate of Atlas Resource Partners, L.P. and received proceeds of approximately $187 million, subject to final post-closing adjustments. The sale included approximately 221 gross (110 net) wells that as of March 2012, produced at an approximate net rate of 35 MMcfe per day. Estimated proved reserves associated with the divested properties were approximately 312 Bcfe (comprised of 177 Bcfe of proved developed and 135 Bcfe of proved undeveloped reserves), as determined by our third party engineers at year-end 2011. As a result of the sale, the borrowing base under the revolving credit facility was recently reduced from $340 million to $325 million. The reduction in the borrowing base due to the sale of the divested properties was largely offset by the addition of proved reserves, primarily in the Eagle Ford Shale, resulting in a net reduction of $15 million. We used substantially all of the net proceeds from this sale to reduce the outstanding borrowings under our revolving credit facility.

U.K. North Sea. During the first quarter of 2012, we continued development of the Huntington Field. We currently expect production from this field to begin in the fourth quarter of 2012.

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Results of Operations

Three Months Ended March 31, 2012, Compared to the Three Months Ended March 31, 2011

Revenues from oil and gas production for the three months ended March 31, 2012 increased 83% to $80.7 million from $44.1 million for the same period in 2011 primarily due to increased production and higher oil prices partially offset by lower gas prices. Production volumes for the three months ended March 31, 2012 and 2011 were 13.9 Bcfe and 10.7 Bcfe, respectively. The increase in production from the first quarter of 2011 to the first quarter of 2012 was primarily due to increased production from new wells, partially offset by normal production decline and the sale of substantially all of our non-core area Barnett Shale properties to KKR in May 2011. Average natural gas prices decreased 39% to $1.86 per Mcf in the first quarter of 2012 from $3.06 per Mcf in the same period in 2011. Average oil prices increased 24% to $109.74 per barrel from $88.65 per barrel in the same period in 2011.

The following table summarizes production volumes, average sales prices and oil and gas revenues for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,		2012 Period Compared to 2011 Period	
	2012	2011	Increase (Decrease)	% Increase (Decrease)
Production volumes				
Oil and condensate (MBbls)	541	133	408	307%
Natural gas (MMcf)	10,327	9,479	848	9%
NGLs (MMcf)	292	412	(120)	(29)%
Average sales prices				
Oil and condensate (per Bbl)	$ 109.74	$ 88.65	$ 21.09	24%
Natural gas (per Mcf)	1.86	3.06	(1.20)	(39)%
NGLs (per Mcf)	7.40	7.81	(0.41)	(5)%
Oil and gas revenues (In thousands)				
Oil and condensate	$ 59,369	$ 11,830	$ 47,539	402%
Natural gas	19,187	29,011	(9,824)	(34)%
NGLs	2,159	3,217	(1,058)	(33)%
Total oil and gas revenues	$ 80,715	$ 44,058	$ 36,657	83%

Lease operating expenses (including transportation costs of $1.2 million) were $8.4 million (or $0.61 per Mcfe) for the three months ended March 31, 2012 as compared to lease operating expenses (including transportation costs of $1.4 million) of $6.7 million (or $0.62 per Mcfe) for the first quarter of 2011. Lease operating expenses increased due to increased production. The decrease in operating cost per Mcfe is due to the KKR sale (which were higher operating and transportation cost per unit properties) partially offset by the higher operating cost per Mcfe associated with oil production.

Production taxes were $3.1 million (or 3.8% of oil and gas revenues) for the three months ended March 31, 2012 as compared to $0.9 million (or 2.1% of oil and gas revenues) for the three months ended March 31, 2011. The increase in production taxes is due to increased oil and gas production. Production taxes as a percentage of oil and gas revenues increased from 2.1% to 3.8% primarily due to increased oil production, which has a higher effective production tax rate as compared to our natural gas production.

Ad valorem taxes increased to $3.6 million (or $0.26 per Mcfe) for the three months ended March 31, 2012 from $0.7 million ($0.06 per Mcfe) for the same period in 2011. The $2.9 million increase in ad valorem taxes is due to $1.5 million from new oil and gas wells drilled in 2011 and $1.4 million as a result of the commonwealth of Pennsylvania s February 2012 enactment of an impact fee on the drilling of unconventional natural gas wells. Because of the retroactive nature of the impact fee, approximately $1.1 million of the impact fee recognized during the first quarter is attributable to wells drilled prior to 2012.

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Depreciation, depletion and amortization (DD&A) expense for the first quarter of 2012 increased $14.9 million to $31.6 million ($2.28 per Mcfe or $13.68 per BOE) from the DD&A expense for the first quarter of 2011 of $16.7 million ($1.56 per Mcfe or $9.36 per BOE). This $14.9 million increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per Mcfe. The increase in the DD&A rate per Mcfe is largely due to the impact of the significant increase in crude oil reserves in the Eagle Ford that were added in 2011, which have a higher finding cost per equivalent unit than the Company s natural gas reserves.

General and administrative expense increased to $11.5 million for the three months ended March 31, 2012 from $9.2 million for the corresponding period in 2011. The increase was primarily due to increased compensation costs related to an increase in personnel in the first quarter of 2012 as compared to the first quarter of 2011, as well as an increase in office rent and utilities.

The net gain on derivative instruments of $3.0 million in the first quarter of 2012 consisted of an $8.1 million unrealized loss on derivatives and an $11.1 million realized gain on derivatives. The net loss on derivative instruments of $0.2 million in the first quarter of 2011 was comprised of a $10.2 million unrealized loss on derivatives and a $10.0 million realized gain on derivatives.

Interest expense and capitalized interest for the three months ended March 31, 2012 were $17.3 million and $6.0 million, respectively, as compared to $12.2 million and $5.3 million, respectively, for the same period in 2011. The increase in interest expense was primarily due to interest on the $200 million aggregate principal amount of our Senior Notes that were issued in the fourth quarter of 2011.

The effective income tax rates for the three months ending March 31, 2012 and 2011 were 29.9% and 59.0%, respectively. The effective income tax rate for the first quarter of 2012 of 29.9% was lower than the estimated annual effective income tax rate for 2012 of 36.7% as a result of the tax benefit associated with the year-to-date U.K. pre-tax loss during the first quarter of 2012. The effective income tax rate for the first quarter of 2011 of 59.0% was higher than the estimated annual effective income tax rate for 2011 of 36.7% due to revisions of prior period estimates of state income taxes.

Liquidity and Capital Resources

2012 Capital Expenditure Plan and Funding Strategy. For 2012, our Board has approved a U.S. capital expenditure plan of $465.0 million which includes approximately $320.0 million for the Eagle Ford Shale, $62.0 million for the Marcellus Shale, $43.0 million for the Niobrara, $15.0 for the Barnett Shale, and $25.0 million for other areas, inclusive of carries. Planned capital expenditures for the Huntington Field development project in the U.K. North Sea are $35.0 million, all of which is expected to be funded by our Huntington Facility. We intend to finance the remainder of our 2012 capital expenditure plan primarily from the sources described below under Sources and Uses of Cash. Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and development programs and, to a lesser extent, our lease and seismic data acquisition programs. The actual amount of investment could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. For the three months ended March 31, 2012, capital expenditures, net of proceeds from asset sales, exceeded our net cash provided by operations. During the first quarter of 2012, we funded our capital expenditures with cash provided by operations, payments or carried interest relating to our joint ventures with Reliance and GAIL, and borrowings under our revolving credit facility and the Huntington Facility. Potential sources of future liquidity include the following:

Cash on hand and cash generated by operations. Cash flows from operations are highly dependent on commodity prices and market conditions for oilfield services. We hedge a portion of our production to mitigate the risk of a decline in oil and gas prices.

Borrowings under the revolving credit facility and the Huntington Facility. At May 7, 2012, after repayments resulting from the recent sale of Barnett Shale properties, $65.0 million and $30.4 million of borrowings were outstanding under the revolving credit facility and the Huntington Facility, respectively. At May 7, 2012, we also had $1.0 million in letters of credit outstanding under the revolving credit facility, which reduce the amounts available under the revolving credit facility. The amount we are able to borrow with respect to the borrowing base of the revolving credit facility, which borrowing base is currently $325 million, is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

Borrowings under project financing arrangements in certain limited circumstances. As described above, we plan to fund a substantial portion of our remaining costs relating to development of the Huntington Field from our Huntington Facility.

Asset sales. On April 30, 2012, we completed the sale of a substantial portion of our Barnett Shale properties and received proceeds of approximately $187 million, subject to final post-closing adjustments. In order to further fund our capital expenditure plan, we may consider additional sales of certain properties or assets, including our interest in the Huntington field development project in the U.K. North Sea, as well as other properties such as certain of our Gulf Coast properties, that are not part of our core business, or are no longer deemed essential to our future growth, and provided that we are able to sell such assets on terms that are acceptable to us.

Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.

Lease option agreements and land banking arrangements, such as those we have entered into in the Barnett Shale and other plays.

Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage and/or purchase a portion of interests, such as our joint ventures with Reliance in the Marcellus Shale, with GAIL in the Eagle Ford Shale and with Avista in the Utica Shale.

We may consider sale/leaseback transactions of certain capital assets, such as our remaining pipelines and compressors, which are not part of our core oil and gas exploration and production business.

Overview of Cash Flow Activities. Net cash provided by operating activities was $83.2 million and $52.3 million for the three months ended March 31, 2012 and 2011, respectively. The increase was primarily due to increased production, particularly higher crude oil and condensate production in the Eagle Ford Shale and increased oil prices, partially offset by lower gas prices in the first three months of 2012 as compared to the same period in 2011.

Net cash used in investing activities was $226.9 million and $98.9 million for the three months ended March 31, 2012 and 2011, respectively, and increased primarily due to increased capital expenditures particularly related to our increased Eagle Ford drilling program and a reduction in advances for joint operations.

Net cash provided by financing activities for the three months ended March 31, 2012 and 2011 was $139.1 million and $64.5 million, respectively. The increase related primarily to the increased net borrowings under the revolving credit facility during the first three months of 2012 as compared to the first three months of 2011.

Liquidity/Cash Flow Outlook. Economic downturns may adversely affect our ability to access capital markets in the future. We currently believe that cash provided by operating activities, the sale of assets (including our recent sale of Barnett Shale properties) and borrowings under the revolving credit facility and the Huntington Facility will be sufficient to fund our immediate cash flow requirements. Cash provided by operating activities is primarily driven by production and commodity prices. While we have steadily increased production over the last few years, spot and futures prices of natural gas remain depressed. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows that will support our capital expenditures program, we hedge a portion of our production and, as of April 30, 2012, we had hedged approximately 12,497,000 MMBtu (51,000 MMBtu per day for the remainder of 2012) of our estimated May through December 2012 natural gas production at a weighted average floor or swap price of $5.33 per MMBtu relative to WAHA and Houston Ship Channel prices. Additionally, we had hedged approximately 1,176,000 Bbls (4,800 Bbls per day for the remainder of 2012) of our estimated May through December 2012 crude oil production at a weighted average floor or swap price of $86.15 per Bbl relative to NYMEX prices. As of May 7, 2012, we had borrowings outstanding of $65 million after giving effect to proceeds received from the recent sale of Barnett Shale properties, and $30.4

million under our revolving credit facility and Huntington Facility, respectively. Our borrowing base under our revolving credit facility is currently $325 million. At May 7, 2012, we also had $1.0 million in letters of credit outstanding, which reduce the amounts available under the revolving credit facility. Additionally, as noted under Sources and Uses of Cash above, the amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility. The borrowing base is affected by our lenders assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our lenders reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base.

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If cash provided by operating activities, funds from asset sales, funds available under the revolving credit facility and the Huntington Facility and the other sources of cash described under Sources and Uses of Cash are insufficient to fund the remainder of our 2012 capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing alternatives to fund it. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer a portion of our revised 2012 capital expenditure plan, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may use a portion of our internally generated cash flows, proceeds from asset sales or borrowings or cash on hand to reduce debt (including convertible debt) prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings.

Contractual Obligations

During the three months ended March 31, 2012, we entered into and extended long-term drilling contracts, primarily in the Marcellus Shale, that require payments of $2.0 million for the remainder of 2012 and no amounts in future periods.

Financing Arrangements

Senior Secured Revolving Credit Facility

In January 2011, we entered into the revolving credit facility which provides for a borrowing capacity up to the lesser of (i) the Borrowing Base and (ii) $750 million. The revolving credit facility matures on January 27, 2016. It is secured by substantially all of our assets (excluding our Carrizo UK assets described below under Huntington Field Development Project Credit Facility and our Utica Shale assets) and is guaranteed by certain of our subsidiaries: Bandelier Pipeline Holding, LLC, Carrizo (Eagle Ford) LLC, Carrizo Marcellus Holding Inc., Carrizo (Marcellus) LLC, Carrizo (Marcellus) WV LLC, Carrizo (Niobrara) LLC, CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, LLC. Any subsidiary of ours that does not currently guarantee our obligations under our revolving credit facility that subsequently becomes a material domestic subsidiary (as defined under our revolving credit facility) will be required to guarantee our obligations under our revolving credit facility. The initial borrowing base under the revolving credit facility was $350 million, and as of March 31, 2012 the borrowing base was $340 million. After the Spring 2012 borrowing base redetermination, which was effective April 30, 2012, the borrowing base was reduced to $325 million after giving effect to the removal of properties in connection with the recent sale of Barnett Shale properties, largely offset by the addition of proved reserves from our successful ongoing drilling program.

On March 26, 2012, the revolving credit facility was amended to, among other things, (1) extend by two quarters the dates on which the maximum ratio of Total Debt to EBITDA (each as defined in the credit agreement governing the revolving credit facility) steps down and (2) increase the basket available for redemptions of our Convertible Senior Notes from $30 million to $75 million.

We are subject to certain covenants under the terms of the revolving credit facility which include the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than (a) 4.75 to 1.00 for fiscal quarters ending March 31, 2012 and June 30, 2012, (b) 4.25 to 1.00 for fiscal quarters ending September 30, 2012 and December 31, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending March 31, 2013 and thereafter; (2) a Current Ratio of not less than 1.0 to 1.0; (3) a ratio of Senior Debt to EBITDA of not more than 2.50 to 1.00; and (4) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the credit agreement governing the revolving credit facility). At March 31, 2012, the ratio of Total Debt to EBITDA was 4.08 to 1.00, the Current Ratio was 1.00 to 1.00, the ratio of Senior Debt to EBITDA was 0.76 to 1.00 and the ratio of EBITDA to Interest Expense was 4.91 to 1.00. Because the calculation of the financial ratios are made as of a certain date, the financial ratios can fluctuate significantly period to period as the amounts outstanding under the revolving credit facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings.

The revolving credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The revolving credit facility is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the Majority Lenders (as defined in the credit agreement governing the revolving credit facility) may accelerate amounts due under the revolving credit facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

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At March 31, 2012, we had $177 million of borrowings outstanding under the revolving credit facility with a weighted average interest rate of 3.08%. At March 31, 2012, we also had $1.0 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. Future availability under the $325 million borrowing base is subject to the terms and covenants of the revolving credit facility. The revolving credit facility is used to fund ongoing working capital needs and the remainder of our capital expenditure plan to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

U.K. Huntington Field Development Project Credit Facility

On January 28, 2011, we and Carrizo UK, as borrower, entered into the Huntington Facility. The Huntington Facility is secured by substantially all of Carrizo UK s assets and is limited recourse to us. The Huntington Facility provides financing for a substantial portion of Carrizo UK s share of costs associated with the Huntington Field development project in the U.K. North Sea. The Huntington Facility provides for a multicurrency credit facility consisting of (1) a $55 million term loan facility to be used to fund Carrizo UK s share of project development costs, (2) a $6.5 million contingent cost overrun term loan facility and (3) a $22.5 million post-completion credit facility providing for loans and letters of credit to be used to fund certain abandonment and decommissioning costs following project completion.

Availability under each of the term loan facility and the cost overrun facility is subject to borrowing bases that are generally based on consolidated cash flow and debt service projections for Carrizo UK attributable to certain proved reserves in the Huntington Field project. The availability under the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field project. As of April 1, 2012, following the semi-annual redetermination of the borrowing base, the term loan facility and cost overrun facility were $55 million and $6.5 million, respectively.

Initial borrowings under the term loan facility and cost overrun facility were conditioned on, among other things, our having made an approximate $22.5 million equity contribution to Carrizo UK, which was completed during the first quarter of 2011. Prior to project completion, we may be responsible under the Huntington Facility for making an additional equity contribution to Carrizo UK in the event the term loan borrowing base is reduced to a level at or above the amount of borrowings then outstanding. We may also be responsible under the Huntington Facility for making certain additional equity contributions to Carrizo UK in the event of certain specified projected Cost Overruns (as defined in the Huntington Facility). To the extent that the cost overrun facility and any required equity contributions are insufficient, we are responsible for funding any Cost Overruns on a 100% basis. If after project completion, the lenders reasonably determine that Carrizo UK is required to incur additional capital expenditures that were not contemplated by the Huntington Field development plan originally approved by the U.K. Department of Energy and Climate Change, we will be responsible for funding such additional expenditures. We are responsible for making certain other payments under the Huntington Facility, including funding certain projected working capital shortfalls, providing cash collateral for letters of credit issued under the post-completion revolving credit facility and paying certain costs of the required hedging arrangements described below.

The annual interest rate on each borrowing is (a) LIBOR (EURIBOR for euro-denominated loans) for the applicable interest period, plus (b) a margin of (i) 3.50% until the completion of the Huntington Field development project and 3.0% thereafter for the term loan credit facility and post-completion revolving credit facility or (ii) 4.75% for the cost overrun facility.

Borrowings under the term loan and cost overrun facilities are available until the earlier of June 30, 2013 or the achievement of certain project development milestones. The term loan and cost overrun facilities mature on December 31, 2014, subject to acceleration in the event that future projection estimates of remaining reserves in the project area have declined to less than 25% of the level initially projected by Carrizo UK and the lenders. Letters of credit under the post-completion revolving credit facility mature on December 31, 2016. An amendment to the facility was executed on April 17, 2012 which adjusted the repayment of the amounts outstanding under the term loan or cost overrun facility to the following: (i) 45% will be due on June 30, 2013, (ii) 20% will be due on December 31, 2013, (iii) 20% will be due on June 30, 2014, and (iv) the remaining 15% will be due on the final maturity date of December 31, 2014 and accordingly, the amounts outstanding under the Huntington Facility have been presented as long-term debt on our balance sheet.

The Huntington Facility requires Carrizo UK to enter into certain hedging arrangements in order to hedge a specified portion of the Huntington Field project s exposure to fluctuating petroleum prices as well as changes in interest rates or exchange rates, and permits Carrizo UK to enter into additional hedging arrangements. The Huntington Facility places restrictions on Carrizo UK with respect to additional indebtedness, liens, the extension of credit, dividends or other payments to us or our other subsidiaries, investments, acquisitions, mergers, asset dispositions, commodity transactions outside of the mandatory hedging program, transactions with affiliates and other matters.

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The Huntington Facility is subject to customary events of default. If an event of default occurs and is continuing, the Majority Lenders may accelerate amounts due under the Huntington Facility.

As of March 31, 2012, borrowings outstanding under the Huntington Facility were £17.5 million, with a weighted average interest rate of 4.58% and no letters of credit had been issued. The British Pound denominated borrowings were translated to $28.0 million at March 31, 2012, resulting in a $0.9 million transaction loss recorded in Other income (expense), net in the consolidated statements of operations.

Critical Accounting Policies

The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. These policies and estimates are described in our Annual Report on Form 10-K for the year ended December 31, 2011. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: use of estimates, oil and gas properties, oil and gas reserve estimates, derivative instruments, income taxes and commitments and contingencies.

The cost center ceiling exceeded our net capitalized costs for the U.S. cost center at March 31, 2012 by approximately $164.0 million and was based on crude oil and condensate prices of $100.78 per barrel, natural gas liquids prices of $45.19 per barrel and natural gas prices of $2.83 per Mcf (or a volume weighted average price of $5.26 per Mcfe), representing the unweighted average market prices on the first calendar day of each month during the 12-month period ended March 31, 2012. A ten percent increase in the unweighted average market prices for the 12-month period ended March 31, 2012 would have increased the cost center ceiling by approximately $159.4 million to $323.4 million and a ten percent decrease in the unweighted average market prices would have caused an impairment of approximately $60.5 million. This sensitivity analysis is as of March 31, 2012 and, accordingly, does not consider drilling results, production and prices subsequent to March 31, 2012 that may require revisions to our proved reserve estimates.

The cost center ceiling exceeded our net capitalized costs for the U.K. cost center at March 31, 2012 by approximately $131.8 million and was based on crude oil and condensate prices of $114.34 per barrel, representing the unweighted average market prices on the first calendar day of each month during the 12-month period ended December 31, 2011. A ten percent increase in average market prices at December 31, 2011 would have increased the cost center ceiling by approximately $19.6 million and a ten percent decrease in average market prices would have decreased the cost center ceiling by approximately $19.6 million. This sensitivity analysis is as of March 31, 2012 and, accordingly, does not consider drilling results, production and prices subsequent to March 31, 2012 that may require revisions to our proved reserve estimates.

Volatility of Oil and Gas Prices

Our revenues, future rate of growth, results of operations, financial position and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and gas.

We review the carrying value of our oil and gas properties quarterly using the full cost method of accounting. See Summary of Critical Accounting Policies Oil and Gas Properties, in our Annual Report on Form 10-K for the year ended December 31, 2011.

We rely on various types of derivative instruments to manage our exposure to commodity price risk and to provide a level of certainty in our forward cash flows supporting our capital expenditure program. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production for up to 36 months or as required by terms of the revolving credit facility. The derivative instruments are carried at fair value in the consolidated balance sheets, with changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at March 31, 2012 was a net asset of $29.8 million, of which 68% was with Credit Suisse, 13% was with BNP Paribas, 10% was with Societe Generale, 4% was with Shell Energy North America (US) LP, 3% was with Credit Agricole, and 2% was with BBVA Compass. The fair value of derivative instruments at December 31, 2011 was a net asset of $37.3 million, of which 68% was with Credit Suisse, 19% was with BNP Paribas, 6% was with Shell Energy North America (US) LP, 5% was with Credit Agricole, and the remaining 2% was with Societe Generale. Master netting agreements are in place with these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil

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and gas company, we believe we have minimal credit risk and accordingly do not currently require our counterparties to post collateral to support the asset positions of our derivative instruments. As such, we are exposed to credit risk to the extent of nonperformance by the counterparties to our derivative instruments. Although we do not currently anticipate such nonperformance, we continue to monitor the financial viability of our counterparties. Because Credit Suisse, BNP Paribas, Credit Agricole, BBVA Compass, and Societe Generale are lenders under our revolving credit facility, and BNP Paribas and Societe Generale are lenders under our Huntington Facility, we are not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties, as the contracts are secured by the revolving credit facility or the Huntington Facility.

The following sets forth a summary of our U.S. natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of March 31, 2012:

Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2012	13,847,000	$ 5.32	$ 5.45
2013	10,950,000	$ 5.07	$ 5.07

In connection with the natural gas derivative instruments above, the Company has entered into protective put spreads. For the remainder of 2012, at market prices below the short put price of $4.62, the floor price becomes the market price plus the put spread of $1.20 on 5,661,400 of the 13,847,000 MMBtus and the remaining 8,185,600 MMBtus would have a floor price of $5.32.

Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2012	5,661,400	$ 4.62	$ 1.20

In addition to the table above, we sold call positions of 3,650,000 MMBtus at a price of $5.50 per MMBtu for 2014.

The following sets forth a summary of our U.S. crude oil derivative positions at average NYMEX prices as of March 31, 2012:

Period	Volume (in Bbls)	Weighted Average Floor Price ($/Bbls)	Weighted Average Ceiling Price ($/Bbls)
2012	1,320,000	$ 86.15	$ 105.91
2013	1,679,000	$ 87.83	$ 106.94
2014	730,000	$ 92.63	$ 101.33
2015	365,000	$ 94.75	$ 94.75

For the three months ended March 31, 2012 and 2011, we recorded the following related to our derivative instruments:

	Three Months Ended March 31, 2012	2011
	(In thousands)	
Realized gain (loss) on derivative instruments, net	$ 11,133	$ 10,007
Unrealized gain (loss) on derivative instruments, net	(8,095)	(10,194)

Gain (loss) on derivative instruments, net	$ 3,038	$ (187)

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Forward Looking Statements

The statements contained in all parts of this document, including, but not limited to, those relating to the Company s or management s intentions, beliefs, expectations, hopes, projections, assessment of risks, estimations, plans or predictions for the future, including our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, timing and amounts of production, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of oil and gas exploration, acquisition of 3-D seismic data (including number, timing and size of projects), capital expenditure plans, planned evaluation of prospects, probability of prospects having oil and gas, expected production or reserves, pipeline connections, increases in reserves, acreage, working capital requirements, commodity price risk management activities and the impact on our average realized prices, the availability of expected sources of liquidity to implement the Company s business strategies, accessibility of borrowings under our credit facilities, future exploration activity, drilling, completion and fracturing of wells, land acquisitions, production rates, forecasted production, growth in production, development of new drilling programs, participation of our industry partners, exploration and development expenditures, the impact of our business strategies, the benefits, results, effects, availability of and results of new and existing joint ventures and sales transactions, proceeds from sales, and all and any other statements regarding future operations, financial results, business plans and cash needs and other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words anticipate, estimate, expect, may, project, plan, believe and similar expressions are intended to be among the statements th forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, borrowing base determinations and availability under our credit facilities, evaluations of the Company by lenders under our credit facilities, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information, property acquisition risks, availability of equipment, actions by our midstream and other industry partners, weather, availability of financing, actions by lenders, our ability to obtain permits and licenses, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture partners, results of exploration activities, the availability of and completion of land acquisitions, completion and connection of wells, and other factors detailed in the Risk Factors and other sections of our Annual Report on Form 10-K for the year ended December 31, 2011 and in our other filings with the SEC, including this quarterly report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

For information regarding our exposure to certain market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk of our Annual Report on Form 10-K for the year ended December 31, 2011. There have been no material changes to the disclosure regarding our exposure to certain market risks made in our Annual Report on Form 10-K for the year ended December 31, 2011.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. They concluded that the controls and procedures were effective as of March 31, 2012 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC s rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended March 31, 2012 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

Item 1A. Risk Factors

There were no material changes to the factors discussed in Part I. Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuance of Warrants to Purchase Common Stock under the Land Agreement. On November 24, 2009, the Company entered into a Land Agreement, as amended (the Land Agreement), with an unrelated third party and its affiliate. In January 2012, the Company issued additional warrants to purchase 6,983 shares, respectively of the Company s common stock to the third party s affiliate for leases acquired prior to the expiration of the Land Agreement. The warrants are subject to antidilution adjustments and may be exercised on a cashless basis. The warrants were issued pursuant to an exemption from registration under §4(2) of the Securities Act of 1933, as amended.

See Note 7. Shareholders Equity for further discussion of the Land Agreement.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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Item 6. Exhibits

The following exhibits are required by Item 601 of Regulation S-K and are filed as part of this report:

Exhibit Number	Exhibit Description
2.1	Purchase and Sale Agreement, dated as of March 15, 2012, among ARP Barnett, LLC and Carrizo Oil & Gas, Inc., CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, Inc. (incorporated herein by reference to Exhibit 2.1 to the Company s Current Report on Form 8-K filed on May 2, 2012).
*10.1	First Amendment, dated as of March 26, 2012, to Credit Agreement dated as of January 27, 2011, among Carrizo Oil & Gas, Inc., BNP Paribas as administrative agent, and the Lenders party thereto.
*10.2	First Amendment, entered into as of April 17, 2012, to Senior Secured Multicurrency Credit Facility Agreement dated as of January 28, 2011, among Carrizo U.K. Huntington Ltd., as Borrower, Carrizo Oil & Gas, Inc., as Parent, and BNP Paribas and Societe Generale as Lead Arrangers, Bookrunners and Original Lenders.
*31.1	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive Data Files

* Filed herewith.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

	Carrizo Oil & Gas, Inc.
	(Registrant)
Date: May 9, 2012	By: /s/ Paul F. Boling Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)
Date: May 9, 2012	By: /s/ David L. Pitts Vice President and Chief Accounting Officer (Principal Accounting Officer)

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