Matador Resources Co
Form 10-Q
November 14, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2012

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 001-35410

MATADOR RESOURCES COMPANY

(Exact name of registrant as specified in its charter)

Texas	**27-4662601**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
5400 LBJ Freeway, Suite 1500 Dallas, Texas 75240	**75240**
(Address of principal executive offices)	**(Zip Code)**

(972) 371-5200

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer ¨
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes x No

As of November 14, 2012, there were 55,569,667 shares of the registrant s common stock, par value $0.01 per share, outstanding.

MATADOR RESOURCES COMPANY

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2012

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Part I Financial Information

Item 1. Financial Statements

Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED BALANCE SHEETS - UNAUDITED

(In thousands, except par value and share data)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,178	$ 10,284
Certificates of deposit	266	1,335
Accounts receivable		
Oil and natural gas revenues	17,046	9,237
Joint interest billings	4,252	2,488
Other	591	1,447
Derivative instruments	6,395	8,989
Lease and well equipment inventory	1,478	1,343
Prepaid expenses	974	1,153
Total current assets	35,180	36,276
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	654,292	423,945
Unproved and unevaluated	164,514	162,598
Other property and equipment	24,597	18,764
Less accumulated depletion, depreciation and amortization	(295,042)	(205,442)
Net property and equipment	548,361	399,865
Other assets		
Derivative instruments	1,880	847
Deferred income taxes	1,878	1,594
Other assets	1,537	887
Total other assets	5,295	3,328
Total assets	$ 588,836	$ 439,469
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 17,364	$ 18,841
Accrued liabilities	50,262	25,439
Royalties payable	5,920	1,855
Borrowings under Credit Agreement		25,000
Derivative instruments		171
Advances from joint interest owners	1,782	
Income taxes payable	188	

Deferred income taxes	1,878	3,024
Dividends payable - Class B		69
Other current liabilities	56	177
Total current liabilities	77,450	74,576
Long-term liabilities		
Borrowings under Credit Agreement	106,000	88,000
Asset retirement obligations	4,551	3,935
Derivative instruments	142	383
Other long-term liabilities	1,465	1,060
Total long-term liabilities	112,158	93,378
Commitments and contingencies (Note 10)		
Shareholders equity		
Common stock - Class A, $0.01 par value, 80,000,000 shares authorized; 56,697,718 and 42,916,668 shares issued; 55,505,209 and 41,737,493 shares outstanding, respectively	567	429
Common stock - Class B, $0.01 par value, zero and 2,000,000 shares authorized; zero and 1,030,700 shares issued and outstanding, respectively		10
Additional paid-in capital	403,248	263,562
Retained earnings	6,178	18,279
Treasury stock, at cost, 1,192,509 and 1,179,175 shares, respectively	(10,765)	(10,765)
Total shareholders equity	399,228	271,515
Total liabilities and shareholders equity	$ 588,836	$ 439,469

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

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Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - UNAUDITED

(In thousands, except per share data)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues				
Oil and natural gas revenues	$ 38,008	$ 17,447	$ 103,250	$ 52,009
Realized gain on derivatives	3,371	1,435	11,147	4,237
Unrealized (loss) gain on derivatives	(12,993)	2,870	(1,149)	1,534
Total revenues	28,386	21,752	113,248	57,780
Expenses				
Production taxes and marketing	2,822	1,848	7,605	4,801
Lease operating	6,491	2,065	17,511	5,639
Depletion, depreciation and amortization	21,680	7,288	52,799	22,578
Accretion of asset retirement obligations	59	61	170	158
Full-cost ceiling impairment	3,596		36,801	35,673
General and administrative	3,439	4,207	11,321	9,919
Total expenses	38,087	15,469	126,207	78,768
Operating (loss) income	(9,701)	6,283	(12,959)	(20,988)
Other income (expense)				
Net loss on asset sales and inventory impairment			(60)	
Interest expense	(144)	(171)	(453)	(461)
Interest and other income	55	82	157	248
Total other expense	(89)	(89)	(356)	(213)
(Loss) income before income taxes	(9,790)	6,194	(13,315)	(21,201)
Income tax provision (benefit)				
Current	188		188	(46)
Deferred	(781)		(1,430)	(6,906)
Total income tax benefit	(593)		(1,242)	(6,952)
Net (loss) income	$ (9,197)	$ 6,194	$ (12,073)	$ (14,249)
Earnings (loss) per common share				
Basic				
Class A	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B	$	$ 0.21	$ (0.03)	$ (0.14)
Diluted				
Class A	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)

Class B	$	$ 0.21	$ (0.03)	$ (0.14)
Weighted average common shares outstanding				
Basic				
Class A	55,271	41,720	53,379	41,671
Class B		1,031	140	1,031
Total	55,271	42,751	53,519	42,702
Diluted				
Class A	55,271	41,848	53,379	41,671
Class B		1,031	140	1,031
Total	55,271	42,879	53,519	42,702

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

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Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY - UNAUDITED

(In thousands)

For the nine months ended September 30, 2012

	Common stock				Additional				
	Class A		Class B		paid-in	Retained	Treasury stock		
	Shares	Amount	Shares	Amount	capital	earnings	Shares	Amount	Total
Balance at January 1, 2012	42,917	$ 429	1,031	$ 10	$ 263,562	$ 18,279	(1,179)	$ (10,765)	$ 271,515
Issuance of Class A common stock	12,209	122			146,388				146,510
Cost to issue equity					(11,268)				(11,268)
Conversion of Class B common stock to Class A common stock	1,031	10	(1,031)	(10)					
Issuance of Class A common stock to Board advisors	7				71				71
Stock options expense					379				379
Stock options exercised	295	3			3,541				3,544
Liability based stock option awards forfeited or expired					192				192
Restricted stock issued	239	3			(3)				
Restricted stock forfeited					(29)		(13)		(29)
Restricted stock and restricted stock units expense					391				391
Swing sale profit contribution					24				24
Class B dividends declared						(28)			(28)
Current period net loss						(12,073)			(12,073)
Balance at September 30, 2012	56,698	$ 567		$	$ 403,248	$ 6,178	(1,192)	$ (10,765)	$ 399,228

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

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Matador Resources Company and Subsidiaries

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - UNAUDITED

(In thousands)

	Nine Months Ended September 30,	
	2012	2011
Operating activities		
Net loss	$ (12,073)	$ (14,249)
Adjustments to reconcile net loss to net cash provided by operating activities		
Unrealized loss (gain) on derivatives	1,149	(1,534)
Depletion, depreciation and amortization	52,799	22,578
Accretion of asset retirement obligations	170	158
Full-cost ceiling impairment	36,801	35,673
Stock option and grant expense	(585)	1,379
Restricted stock and restricted stock units expense	362	36
Deferred income tax benefit	(1,430)	(6,906)
Loss on asset sales and inventory impairment	60	
Changes in operating assets and liabilities		
Accounts receivable	(8,718)	(2,411)
Lease and well equipment inventory	(285)	(1)
Prepaid expenses	179	240
Other assets	(650)	
Accounts payable, accrued liabilities and other liabilities	6,105	(2,360)
Income taxes payable	188	
Royalties payable	4,065	2,548
Advances from joint interest owners	1,782	(723)
Other long-term liabilities	406	15
Net cash provided by operating activities	80,325	34,443
Investing activities		
Oil and natural gas properties capital expenditures	(212,702)	(104,733)
Expenditures for other property and equipment	(5,297)	(3,303)
Purchases of certificates of deposit	(416)	(3,721)
Maturities of certificates of deposit	1,485	3,985
Net cash used in investing activities	(216,930)	(107,772)
Financing activities		
Repayments of borrowings under Credit Agreement	(123,000)	
Borrowings under Credit Agreement	116,000	60,000
Proceeds from issuance of common stock	146,510	592
Swing sale profit contribution	24	
Cost to issue equity	(11,599)	(1,185)
Proceeds from stock options exercised	2,660	837
Payment of dividends - Class B	(96)	(206)
Net cash provided by financing activities	130,499	60,038
Decrease in cash and cash equivalents	(6,106)	(13,291)
Cash and cash equivalents at beginning of period	10,284	21,059

Cash and cash equivalents at end of period	$ 4,178	$ 7,768
Supplemental disclosures of cash flow information (Note 11)		

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

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED

NOTE 1 - NATURE OF OPERATIONS

Matador Resources Company (Matador or the Company) is an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Matador s current operations are located primarily in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana and East Texas. In addition to these primary operating areas, Matador has acreage positions in Southeast New Mexico and West Texas and in Southwest Wyoming and adjacent areas in Utah and Idaho where the Company continues to identify new oil and natural gas prospects.

On November 22, 2010, the company formerly known as Matador Resources Company, a Texas corporation founded on July 3, 2003, formed a wholly-owned subsidiary, Matador Holdco, Inc. Pursuant to the terms of a corporate reorganization that was completed on August 9, 2011, the former Matador Resources Company became a wholly owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

MRC Energy Company holds the primary assets of the Company and has four wholly owned subsidiaries: Matador Production Company, MRC Permian Company, MRC Rockies Company and Longwood Gathering and Disposal Systems GP, Inc. Matador Production Company serves as the oil and natural gas operating entity. MRC Permian Company conducts oil and natural gas exploration and development activities in Southeast New Mexico. MRC Rockies Company conducts oil and natural gas exploration and development activities in the Rocky Mountains and specifically in the states of Wyoming, Utah and Idaho. Longwood Gathering and Disposal Systems GP, Inc. serves as the general partner of Longwood Gathering and Disposal Systems, LP which owns a majority of the pipeline systems and salt water disposal wells used in the Company s operations and also transports limited quantities of third-party natural gas.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Interim Financial Statements, Basis of Presentation, Consolidation and Significant Estimates

The unaudited condensed consolidated financial statements of Matador and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission (SEC) but do not include all of the information and footnotes required by generally accepted accounting principles in the United States of America (U.S. GAAP) for complete financial statements and should be read in conjunction with the Company s 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 filed with the SEC. All intercompany accounts and transactions have been eliminated in consolidation. In management s opinion, these interim unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair presentation of the Company s consolidated financial position as of September 30, 2012, consolidated results of operations for the three and nine months ended September 30, 2012 and 2011, consolidated changes in shareholders equity for the nine months ended September 30, 2012 and consolidated cash flows for the nine months ended September 30, 2012 and 2011. Certain reclassifications have been made to prior period items to conform to the current period presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings. Amounts as of December 31, 2011 are derived from the audited consolidated financial statements as filed with the SEC in our Annual Report on Form 10-K for the year ended December 31, 2011.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results for the interim periods shown in this report are not necessarily indicative of results to be expected for the full year due in part to volatility in oil and natural gas prices, global economic and financial market conditions, interest rates, access to sources of liquidity, estimates of reserves, drilling risks, geological risks, transportation restrictions, oil and natural gas supply and demand, market competition and interruptions of production.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The Company s consolidated financial statements are based on a number of significant estimates, including accruals for oil and natural gas revenues, accrued assets and liabilities primarily related to oil and natural gas operations, stock-based compensation, valuation of derivative instruments and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company s activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized approximately $1.7 million and $1.3 million of its general and administrative costs for the nine months ended September 30, 2012 and 2011, respectively. The Company capitalized approximately $1.0 million and $0.8 million of its interest expenses for the nine months ended September 30, 2012 and 2011, respectively.

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center ceiling, with any excess above the cost center ceiling charged to operations as a full-cost ceiling impairment. The need for a full-cost ceiling impairment is assessed on a quarterly basis. The cost center ceiling is defined as the sum of (a) the present value discounted at 10 percent of future net revenues of proved oil and natural gas reserves, plus (b) unproved and unevaluated property costs not being amortized, plus (c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (d) income tax effects related to the properties involved. Future net revenues from proved non-producing and proved undeveloped reserves are reduced by the estimated costs for developing these reserves. The fair value of the Company s derivative instruments is not included in the ceiling test computation as the Company does not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent on the commodity prices used in these estimates. These estimates are determined in accordance with guidelines established by the SEC for estimating and reporting oil and natural gas reserves. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements.

The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period October 2011 through September 2012, these average oil and natural gas prices were $91.48 per Bbl and $2.826 per MMBtu (million British thermal units), respectively. For the period October 2010 through September 2011, these average oil and natural gas prices were $91.00 per Bbl and $4.158 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were adjusted by property for energy content, transportation and marketing fees and regional price differentials. At September 30, 2012 and 2011, the Company s oil and natural gas reserves estimates were prepared by the Company s engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Using the average commodity prices, as adjusted, to determine the Company s estimated proved oil and natural gas reserves at September 30, 2012, the Company s net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. The Company recorded an impairment charge of $3.6 million to its net capitalized costs and a deferred income tax credit of $1.3, related to the full-cost ceiling limitation at September 30, 2012. The Company recorded no impairment to its net capitalized costs and no corresponding charge to its unaudited condensed consolidated statements of operations for the three months ended September 30, 2011. Using the average commodity prices, as adjusted, to determine the Company s estimated proved oil and natural gas reserves at June 30, 2012, the Company s net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. The Company recorded an impairment charge of $33.2 million to its net capitalized costs and a deferred income tax credit of $11.9 million related to the full-cost ceiling limitation at June 30, 2012. At March 31, 2011, the Company s net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $23.0 million. The Company recorded an impairment charge of $35.7 million to its net capitalized costs and a deferred income tax credit of $12.7 million related to the full-cost ceiling limitation at March 31, 2011. These charges are reflected in the Company s unaudited condensed consolidated statement of operations for the nine months ended September 30, 2012 and 2011. Changes in oil and natural gas production rates, reserves estimates, future development costs and other factors will determine the Company s actual ceiling test computation and impairment analyses in future periods.

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company s assets on its balance sheet, as well as the corresponding shareholders equity, but it has no impact on the Company s net cash flows as reported.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Dry holes are included in the amortization base immediately upon determination that the well is not productive.

Earnings Per Common Share

The Company reports basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

Prior to the consummation of the Company s Initial Public Offering (see Note 7) in February 2012, the Company had issued two classes of common stock, Class A and Class B. The holders of the Class B shares were entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends were accrued and paid quarterly. Dividends declared during the three months ended September 30, 2012 and 2011 totaled zero and $68,713, respectively. Dividends declared during the nine months ended September 30, 2012 and 2011 totaled $27,643 and $206,140, respectively, in each period. Class B dividends declared during the fourth quarter of 2011 and the first quarter of 2012 were paid during the first quarter of 2012 totaling $96,356. As of September 30, 2012, the Company had not paid any dividends to holders of the Class A shares. Concurrent with the completion of the Initial Public Offering, all 1,030,700 shares of the Company s Class B common stock were converted to Class A common stock on a one-for-one basis. The Class A common stock is now referred to as the common stock.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

The following are reconciliations of the numerators and denominators used to compute the Company s basic and diluted distributed and undistributed earnings (loss) per common share as reported for the three and nine months ended September 30, 2012 and 2011 (in thousands, except per share amounts).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net (loss) income - numerator				
Net (loss) income	$ (9,197)	$ 6,194	$ (12,073)	$ (14,249)
Less dividends to Class B shareholders - distributed earnings		(69)	(28)	(206)
Undistributed (loss) earnings	$ (9,197)	$ 6,125	$ (12,101)	$ (14,455)
Weighted average common shares outstanding - denominator				
Basic				
Class A	55,271	41,720	53,379	41,671
Class B		1,031	140	1,031
Total	55,271	42,751	53,519	42,702
Diluted				
Class A				
Weighted average common shares outstanding for basic earnings (loss) per share	55,271	41,720	53,379	41,671
Dilutive effect of options and restricted stock units		128		
Class A weighted average common shares outstanding - diluted	55,271	41,848	53,379	41,671
Class B				
Weighted average common shares outstanding - associated no associated dilutive shares		1,031	140	1,031
Total diluted weighted average common shares outstanding	55,271	42,879	53,519	42,702

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Earnings (loss) per common share				
Basic				
Class A				
Distributed earnings	$	$	$	$
Undistributed (loss) earnings	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Total	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B				
Distributed earnings	$	$ 0.07	$ 0.20	$ 0.20
Undistributed earnings (loss)	$	$ 0.14	$ (0.23)	$ (0.34)
Total	$	$ 0.21	$ (0.03)	$ (0.14)
Diluted				
Class A				
Distributed earnings	$	$	$	$
Undistributed (loss) earnings	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Total	$ (0.17)	$ 0.14	$ (0.23)	$ (0.34)
Class B				
Distributed earnings	$	$ 0.07	$ 0.20	$ 0.20
Undistributed earnings (loss)	$	$ 0.14	$ (0.23)	$ (0.34)
Total	$	$ 0.21	$ (0.03)	$ (0.14)

A total of 1,085,152 options to purchase the Company s Class A common stock and 151,051 restricted stock units were excluded from the calculations above for the three and nine months ended September 30, 2012 because their effects were anti-dilutive. Additionally, 233,349 restricted shares, which are participating securities, were excluded from the calculations above for the three and nine months ended September 30, 2012 as the security holders do not have the obligation to share in the losses of the Company. A total of 1,024,500 options to purchase shares of the Company s Class A common stock were excluded from the calculations above for the nine months ended September 30, 2011 because their effects were anti-dilutive. These options were included in the calculations above for the three months ended September 30, 2011.

Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company follows Financial Accounting Standards Board (FASB) guidance establishing a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Recent Accounting Pronouncements

Balance Sheet. In December 2011, the FASB issued Accounting Standards Update, or ASU, 2011-11, *Balance Sheet*. The requirements amend the disclosure requirements related to offsetting in Accounting Standard s Codification, or ASC, 210-20-50. The amendments require enhanced disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The adoption of ASU 2011-11 is not expected to have a material effect on the Company s consolidated financial statements, but may require certain additional disclosures. The amendments in ASU 2011-11 are to be applied for annual reporting periods beginning on or after January 1, 2013 and are to be applied retrospectively for all periods presented.

Fair Value. In May 2011, the FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*. ASU 2011-04 amends ASC 820, *Fair Value Measurements*, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. The Company adopted ASU 2011-04 on January 1, 2012; adoption did not have a material effect on the Company s consolidated financial statements, but did require additional disclosures.

NOTE 3 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company s asset retirement obligations for the nine months ended September 30, 2012 (in thousands).

Beginning asset retirement obligations	$ 4,269
Liabilities incurred during period	459
Liabilities settled during period	
Accretion expense	170
Ending asset retirement obligations	$ 4,898

At September 30, 2012, approximately $0.3 million of the Company s asset retirement obligations were classified as current liabilities and included in accrued liabilities in the Company s unaudited condensed consolidated balance sheet (see Note 11).

NOTE 4 - REVOLVING CREDIT AGREEMENT

On September 28, 2012, the Company amended and restated its senior secured revolving credit agreement. This third amended and restated credit agreement (Credit Agreement) increased the maximum facility amount from $400 million to $500 million and named Royal Bank of Canada (RBC) as administrative agent. Under the Credit Agreement, the borrowing base was increased to $200 million from the previous borrowing base of $125 million. In addition, the Credit Agreement provides for a conforming borrowing base of $165 million. The borrowing base will automatically be reduced to the conforming borrowing base on the earlier of (i) December 31, 2013 or (ii) the closing of a secondary public offering of equity interests by the Company that results in net cash proceeds to the Company in an amount greater than or equal to $25 million. The Credit Agreement matures in December 2016. The Credit Agreement superseded the second amended and restated credit agreement which had been entered into by the Company on December 30, 2011. The second amended and restated credit agreement increased the maximum facility amount from $150 million to $400 million, and borrowings under the Credit Agreement were limited to the lower of $400 million or the borrowing base which was then set at $125 million.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

MRC Energy Company is the borrower under the Credit Agreement, and borrowings are secured by mortgages on substantially all of the Company s oil and natural gas properties and by the equity interests of all of MRC Energy Company s wholly owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with RBC and Comerica Bank (or affiliates thereof) are also secured by the collateral and guaranteed by Matador Resources Company and the subsidiaries of MRC Energy Company.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company s proved oil and natural gas reserves, but also on external factors, such as the lenders lending policies and the lenders estimates of future oil and natural gas prices, over which the Company has no control. At December 31, 2011, the borrowing base was $125 million and the Company had $113 million in outstanding borrowings under the Credit Agreement. In January 2012, the Company borrowed an additional $10 million to finance a portion of its working capital requirements and capital expenditures, bringing the then outstanding revolving borrowings under the Credit Agreement to $123 million. Following the completion of the Initial Public Offering in February 2012, the Company used a portion of the net proceeds to repay the then outstanding $123 million under the Credit Agreement in full, at which time the borrowing base was reduced to $100 million. On February 28, 2012, the borrowing base was increased to $125 million pursuant to a special borrowing base redetermination made at the Company s request. The borrowing base increase was determined by the lenders based upon, among other items, the increase in the Company s oil and natural gas reserves at December 31, 2011.

Between March 1, 2012 and September 30, 2012, the Company borrowed $106 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures. At September 30, 2012, the Company had $106 million in borrowings outstanding under the Credit Agreement, approximately $1.1 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $92.9 million available for additional borrowings. At September 30, 2012, the Company s outstanding borrowings bore interest at an effective rate of approximately 5.3% per annum as the borrowings were outstanding as a base rate advance. In early October, the borrowings were converted to a Eurodollar-based rate advance and bore interest at an effective rate of approximately 3.3% per annum.

Both the Company and the lenders may each request one unscheduled redetermination of the borrowing base between scheduled redetermination dates. In the event of a borrowing base increase, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which will be determined based on market conditions at the time of the borrowing base increase. If the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

If the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day or (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.75% to 2.25% of such outstanding loan depending on the level of borrowings under the Credit Agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which RBC is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.75% to 3.25% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee and any loan amortization costs in its interest rate calculations and related disclosures.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

Key financial covenants under the Credit Agreement require the Company to maintain (1) a current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by consolidated total current liabilities, of 1.0 or greater measured at the end of each fiscal quarter beginning March 31, 2013 and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 or less.

Subject to certain exceptions, the Credit Agreement contains various covenants that limit the Company s, along with its subsidiaries , ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of its assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of the Company s assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;

- bankruptcy or insolvency events involving the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

At September 30, 2012, the Company believes that it was in compliance with the terms of the Credit Agreement.

NOTE 5 - INCOME TAXES

The Company had a net loss for the three and nine months ended September 30, 2012 and a net loss for the nine months ended September 30, 2011. The Company established a valuation allowance at September 30, 2012 of approximately $2.4 million due to uncertainties regarding the future realization of its deferred tax assets. The Company established a valuation allowance at March 31, 2011 and retained a valuation allowance of approximately $0.8 million at September 30, 2011, due to uncertainties regarding the future realization of its deferred tax assets. As a result, there was no income tax expense recorded for the three months ended September 30, 2011.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 5 - INCOME TAXES - Continued

During the first quarter of 2012, the Company recorded an adjustment to the estimated permanent differences between book and taxable income related to stock compensation expense in prior periods. The adjustment resulted in a charge to deferred tax assets and additional deferred income taxes of approximately $0.7 million, which is reflected in the Company s statement of operations for the nine months ended September 30, 2012. During the third quarter of 2012, the Company recorded an adjustment to the estimated permanent differences between book and taxable income related to an acquisition in a prior period. The adjustment resulted in a charge to deferred tax assets and additional deferred income taxes of approximately $0.2 million which is reflected in the Company s statement of operations for the nine months ended September 30, 2012. Although the total adjustments made during the year may be considered material to the financial results for the nine months ended September 30, 2012, the Company does not believe that the adjustment will have a material impact on the financial results for the year ended December 31, 2012.

NOTE 6 - STOCK-BASED COMPENSATION

Effective January 1, 2012, the Board of Directors adopted the 2012 Long-Term Incentive Plan (the 2012 Incentive Plan). The 2012 Incentive Plan was also approved by the Company s shareholders at its Annual Meeting of Shareholders on June 7, 2012. The 2012 Incentive Plan provides for a maximum of four million shares of common stock in the aggregate that may be issued by the Company pursuant to grants of stock options, restricted stock, stock appreciation rights, restricted stock units and other performance awards. The persons eligible to receive awards under the 2012 Incentive Plan include employees, contractors and outside directors of the Company. The primary purpose of the 2012 Incentive Plan is to attract and retain key employees, key contractors and outside directors of the Company.

In February 2012, the Company granted one of its executive officers the option to purchase 150,000 shares of its common stock at $12.00 per share. The award was classified as an equity award, vesting over a service period of approximately three years. The total grant date fair value of the option was approximately $1.1 million. The Company reversed previously recognized stock-based compensation expense related to this grant of approximately $70,000 at June 30, 2012, as the executive officer terminated his employment with the Company in July 2012, and therefore, the service condition requirement for this award was not met.

On April 16, 2012, the Board of Directors approved an award of stock options, restricted stock and restricted stock units to both executive and non-executive employees under the 2012 Incentive Plan. Non-qualified options to purchase an aggregate of 472,318 shares of the Company s common stock at $10.49 per share were awarded; these options vest over four years. A total of 116,842 shares of time-lapse restricted stock was granted, and these shares also vest over four years. A total of 116,841 shares of performance-based restricted stock was granted. These shares vest based on the outcome of the Company s total shareholder return over a three-year period as compared to a designated peer group. This award may result in the issuance of an aggregate of up to 116,841 restricted stock units in addition to the restricted stock grants. If the minimum performance conditions are not met, however, this award may also result in no performance-based restricted stock being vested and no restricted stock units being issued. The grant date fair value of all of these awards is approximately $5.5 million.

On April 11, 2012, June 29, 2012 and September 13, 2012, the Company awarded 13,608, 12,215 and 12,755 restricted stock units, respectively, to its Board of Directors and one advisor to the Board as payment for their services to the Company during the first, second and third quarters of 2012. The restricted stock units vest over three years and have an aggregate grant date fair value of approximately $0.4 million.

On April 11, 2012, June 29, 2012 and September 13, 2012, the Company issued 500 shares of common stock to each of two advisors to the Board of Directors (aggregate of 1,500 shares issued per advisor) as payment for their services to the Company during the first, second and third quarters of 2012. The fair value of these awards was $11,020, $10,740 and $10,270, respectively, which was recorded as an expense during the three months ended March 31, 2012, June 30, 2012 and September 30, 2012, respectively. On June 6, 2012, the Company issued 4,000 shares of common stock to a retiring director as payment for his services during the second quarter of 2012. The fair value of this award was $38,840, which was recorded as an expense during the nine months ended September 30, 2012.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 6 - STOCK-BASED COMPENSATION - Continued

On September 28, 2012, the Company granted an employee the option to purchase 20,000 shares of its common stock at $10.39 per share. The award was classified as an equity award, vesting over a service period of four years. The total grant date fair value of the options was $110,646. Additionally, the Company issued this employee 5,000 shares of restricted stock vesting over a four-year service period; the grant date fair value of this award was $51,950.

NOTE 7 - COMMON STOCK

On August 12, 2011, the Company filed a Form S-1 Registration Statement under the Securities Act of 1933 to commence the initial public offering of its common stock (the Initial Public Offering). The Company s Registration Statement (File 333-176263), as amended, was declared effective by the SEC on February 1, 2012. The underwriters for the Company s Initial Public Offering were RBC Capital Markets, LLC; Citigroup Global Markets, Inc.; Jefferies & Company, Inc.; Howard Weil Incorporated; Stifel, Nicolaus & Company, Incorporated; Simmons & Company International; Stephens Inc.; and Comerica Securities, Inc. On February 2, 2012, shares of the Company s common stock began trading on the New York Stock Exchange under the symbol MTDR at an initial offering price of $12.00 per share.

Pursuant to its Prospectus dated February 1, 2012, the Company and the selling shareholders offered 13,333,334 shares of the Company s common stock for sale. The Company offered 11,666,667 shares of its common stock, and the selling shareholders offered 1,666,667 shares. On February 7, 2012, the Company closed the Initial Public Offering and issued 11,666,667 shares of its common stock pursuant to the Initial Public Offering.

The Company and the selling shareholders granted the underwriters the right to purchase up to an additional 2,000,000 shares of the Company s common stock at the initial offering price of $12.00 per share, less the underwriters discounts and commissions, for a period of 30 days following the Initial Public Offering to cover over-allotments, with the Company offering 700,000 shares and the selling shareholders offering 1,300,000 shares. On March 2, 2012, the underwriters exercised their option to purchase an additional 1,550,000 shares, including the purchase of 542,500 shares from the Company and the purchase of 1,007,500 shares from the selling shareholders. On March 7, 2012, the Company closed this transaction and issued 542,500 shares of its common stock pursuant to the underwriters exercise of the over-allotment.

Pursuant to the Initial Public Offering and the over-allotment, the Company issued a total of 12,209,167 shares of its common stock at $12.00 per share. The Company received cash proceeds of approximately $136.6 million from this transaction, net of underwriting discounts and commissions. The Company did not receive any proceeds from the sale of shares of its common stock by the selling shareholders. The underwriters received underwriting discounts and commissions totaling approximately $9.9 million, and the Company incurred additional costs of approximately $3.5 million in connection with the offering, which amounted to total fees and costs of approximately $13.4 million, of which approximately $2.1 million was incurred in a prior period. On February 8, 2012, the Company used a portion of the net proceeds of the offering to repay the $123.0 million in borrowings then outstanding under its Credit Agreement in full. The Company used the remaining net proceeds of the offering to fund a portion of its 2012 capital expenditures.

Concurrent with the completion of the Initial Public Offering, all 1,030,700 shares of the Company s Class B common stock were converted to Class A common stock on a one-for-one basis. In addition, in February 2012, the Company issued an additional 295,500 shares of its Class A common stock pursuant to the exercise of stock options and received net proceeds of $2.7 million. The Class A common stock is now referred to as the common stock.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. These instruments consist of put and call options in the form of costless collars and swap contracts. The Company records derivative financial instruments on its balance sheet as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations as an unrealized gain or loss. The fair value of the Company s derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Comerica Bank and RBC (or affiliates thereof) are the counterparties for our commodity derivatives. We have considered the credit standings of the counterparties in determining the fair value of our derivative financial instruments.

The Company has entered into various costless collar contracts to mitigate its exposure to fluctuations in oil prices on a portion of its future anticipated oil production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company pursuant to any of these transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period s calendar month. When the settlement price is below the price floor established by these collars, the Company receives from its counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by these collars the Company pays to its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

The Company has entered into various costless collar transactions to mitigate its exposure to fluctuations in natural gas prices on a portion of its future anticipated natural gas production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period s calendar month for the last day of that contract period. When the settlement price is below the price floor established by these collars, the Company receives from its counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by these collars, the Company pays to its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

In August 2012, the Company entered into various swap contracts to mitigate its exposure to fluctuations in natural gas liquids (NGL) prices on a portion of its future anticipated NGL production, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to the Company pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity as stated on the Mont Belvieu Spot Gas Liquids Prices: NON-TET prop on the pricing date. When the settlement price is below the fixed price established by these swaps, the Company receives from its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by these swaps the Company pays to its counterparty an amount equal to the difference between the settlement and the fixed price multiplied by the contract NGL volume.

At September 30, 2012, the Company had multiple costless collar contracts open and in place to mitigate its exposure to oil and natural gas price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling. Each contract is set to expire at varying times during 2012, 2013 and 2014.

At September 30, 2012, the Company had multiple swap contracts open and in place to mitigate its exposure to NGL price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and fixed price. Each contract is set to expire at varying times during 2012 and 2013.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following is a summary of the Company s open costless collar contracts for oil and natural gas and open swap contracts for natural gas liquids at September 30, 2012.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (thousands)
Oil	10/01/2012 - 12/31/2012	20,000	90.00	104.20	$ 113
Oil	10/01/2012 - 12/31/2012	10,000	90.00	108.00	65
Oil	10/01/2012 - 12/31/2012	10,000	90.00	109.50	68
Oil	10/01/2012 - 12/31/2012	20,000	90.00	111.00	139
Oil	10/01/2012 - 12/31/2012	20,000	90.00	111.90	141
Oil	10/01/2012 - 12/31/2012	20,000	95.00	116.00	291
Oil	10/01/2012 - 03/31/2013	20,000	90.00	110.00	356
Oil	01/01/2013 - 12/31/2013	20,000	85.00	102.25	61
Oil	01/01/2013 - 12/31/2013	20,000	90.00	115.00	1,233
Oil	01/01/2013 - 12/31/2013	20,000	85.00	110.40	598
Oil	01/01/2013 - 12/31/2013	20,000	85.00	108.80	515
Oil	01/01/2013 - 06/30/2014	8,000	90.00	114.00	794
Oil	01/01/2013 - 06/30/2014	12,000	90.00	115.50	1,242
Total Oil (open costless collar contracts)					$ 5,616

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	10/01/2012 - 12/31/2012	300,000	4.50	5.60	$ 1,067
Natural Gas	10/01/2012 - 12/31/2012	150,000	4.25	6.17	424
Natural Gas	10/01/2012 - 12/31/2012	70,000	2.50	3.34	(36)
Natural Gas	10/01/2012 - 07/31/2013	150,000	4.50	5.75	1,398
Natural Gas	10/01/2012 - 12/31/2013	100,000	3.00	3.83	(381)
Total Natural Gas (open costless collar contracts)					$ 2,472

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Purity Ethane	10/01/2012 - 12/31/2012	55,700	0.333	$
Purity Ethane	10/01/2012 - 12/31/2012	55,700	0.337	
Propane	10/01/2012 - 12/31/2012	27,000	0.945	1
Propane	10/01/2012 - 12/31/2012	27,000	0.992	5
Normal Butane	10/01/2012 - 12/31/2012	7,500	1.465	
Normal Butane	10/01/2012 - 12/31/2012	7,500	1.580	3
Isobutane	10/01/2012 - 12/31/2012	4,000	1.535	(2)
Isobutane	10/01/2012 - 12/31/2012	4,000	1.675	(1)
Natural Gasoline	10/01/2012 - 12/31/2012	6,000	2.095	2
Natural Gasoline	10/01/2012 - 12/31/2012	6,000	2.150	3
Purity Ethane	01/01/2013 - 12/31/2013	110,000	0.335	(41)
Purity Ethane	01/01/2013 - 12/31/2013	110,000	0.355	(15)
Propane	01/01/2013 - 12/31/2013	53,000	0.953	7
Propane	01/01/2013 - 12/31/2013	53,000	1.001	38
Normal Butane	01/01/2013 - 12/31/2013	14,700	1.455	(3)
Normal Butane	01/01/2013 - 12/31/2013	14,700	1.560	16
Isobutane	01/01/2013 - 12/31/2013	7,000	1.515	(7)
Isobutane	01/01/2013 - 12/31/2013	7,000	1.625	3
Natural Gasoline	01/01/2013 - 12/31/2013	12,000	2.085	17
Natural Gasoline	01/01/2013 - 12/31/2013	12,000	2.102	19
Total NGL s (open swap contracts)				$ 45
Total open derivative financial instruments				$ 8,133

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated balance sheets for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Balance Sheet	September 30, 2012	December 31, 2011
Derivative Instrument			
Oil	Current assets: Derivative instruments	$ 3,736	$
Oil	Other assets: Derivative instruments	1,880	
Oil	Current liabilities: Derivative instruments		(171)
Oil	Long-term liabilities: Derivative instruments		(383)
Natural Gas	Current assets: Derivative instruments	2,610	8,989

Natural Gas	Other assets: Derivative instruments		847
Natural Gas	Long-term liabilities: Derivative instruments	(138)	
NGL s	Current assets: Derivative instruments	49	
NGL s	Long-term liabilities: Derivative instruments	(4)	
Total		$ 8,133	$ 9,282

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 8 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Statement of Operations	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Derivative Instrument					
Oil	Revenues: Realized gain on derivatives	$ 374	$	$ 1,093	$
Natural Gas	Revenues: Realized gain on derivatives	2,996	1,435	10,053	4,237
NGL s	Revenues: Realized gain on derivatives	1		1	
Realized gain on derivatives		3,371	1,435	11,147	4,237
Oil	Revenues: Unrealized (loss) gain on derivatives	(9,053)		(7,364)	
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(3,985)	2,870	6,170	1,534
NGL s	Revenues: Unrealized gain (loss) on derivatives	45		45	
Unrealized (loss) gain on derivatives		(12,993)	2,870	(1,149)	1,534
Total		$ (9,622)	$ 4,305	$ 9,998	$ 5,771

NOTE 9 - FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 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. This category includes those derivative instruments that are valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3 Unobservable inputs that are not corroborated by market data. This category is comprised of financial and non-financial assets and liabilities whose fair value is estimated based on internally developed models or methodologies using significant inputs that are generally less readily observable from objective sources.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

At September 30, 2012 and December 31, 2011, the carrying values reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, income taxes payable, advances from joint owners and other current liabilities approximate their fair values due to their short-term maturities and are classified at Level 1.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

At September 30, 2012 and December 31, 2011, the carrying value of borrowings under the Credit Agreement approximates fair value as it is subject to short-term floating interest rates that reflect market rates available to the Company at the time and is classified at Level 2.

The following tables summarize the valuation of the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of September 30, 2012 and December 31, 2011 (in thousands).

Description		Fair Value Measurements at September 30, 2012 using		
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$	$ 266	$	$ 266
Oil, natural gas and NGL derivatives		8,275		8,275
Oil, natural gas and NGL derivatives		(142)		(142)
Total	$	$ 8,399	$	$ 8,399

Description		Fair Value Measurements at December 31, 2011 using		
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$	$ 1,335	$	$ 1,335
Oil and natural gas derivatives		9,836		9,836
Oil and natural gas derivatives		(554)		(554)
Total	$	$ 10,617	$	$ 10,617

Additional disclosures related to derivative financial instruments are provided in Note 8. For purposes of fair value measurement, the Company determined that certificates of deposit and derivative financial instruments (e.g., oil, natural gas and NGL derivatives) should be classified at Level 2.

The Company accounts for additions to asset retirement obligations and lease and well equipment inventory at fair value on a non-recurring basis. The following tables summarize the valuation of the Company s assets and liabilities that were accounted for at fair value on a non-recurring basis for the periods ended September 30, 2012 and December 31, 2011 (in thousands).

Description	Fair Value Measurements for the period ended September 30, 2012 using

	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$	$	$ (459)	$ (459)
Total	$	$	$ (459)	$ (459)

Description	Fair Value Measurements for the period ended December 31, 2011 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$	$	$ (187)	$ (187)
Lease and well equipment inventory			1,343	1,343
Total	$	$	$ 1,156	$ 1,156

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 9 - FAIR VALUE MEASUREMENTS - Continued

For purposes of fair value measurement, the Company determined that the additions to asset retirement obligations should be classified at Level 3. The Company recorded additions to asset retirement obligations of $459,158 for the nine months ended September 30, 2012 and $186,873 for the year ended December 31, 2011.

For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified as Level 3. In 2011, the Company recorded an impairment to some of its equipment held in inventory consisting primarily of drilling rig parts of $17,500 and pipe and other equipment of $22,276; no impairment to any equipment was recorded for the three and nine months ended September 30, 2012. The Company periodically obtains estimates of the market value of its equipment held in inventory from an independent third-party contractor or seller of similar equipment and uses these estimates as a basis for its measurement of the fair value of this equipment.

NOTE 10 - COMMITMENTS AND CONTINGENCIES

Office Lease

The Company s corporate headquarters are located in 28,743 square feet of office space at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. The lease, as amended on July 1, 2011, expires on June 30, 2022. The effective base rent is $19.75 per square foot per year. The base rate escalates in July 2015, July 2017, July 2019 and July 2020.

Natural Gas and NGL Transportation and Processing Commitments

The Company entered into a firm transportation and processing agreement whereby it has committed to transport its anticipated natural gas and natural gas liquids production from a significant portion of its Eagle Ford acreage in south Texas through the counterparty s pipeline for further processing at the counterparty s facilities. The agreement was effective as of September 1, 2012 and expires on September 1, 2017. The arrangement contains fees that vary based on the price of natural gas, the quality of natural gas transported to the processing facility and the contract period.

If the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the gas deficiency. The Company believes that its current and anticipated production from the wells covered by this agreement is sufficient to meet 80% of the maximum thermal quantity transportation and processing commitments under this agreement. We paid approximately $64,000 in transportation and processing fees under this agreement for the three and nine months ended September 30, 2012.

The aggregate undiscounted minimum commitments under this agreement at September 30, 2012 are as follows (in thousands).

Year ending December 31, 2012	Amount
2012	$ 780
2013	5,985
2014	4,731
2015	2,992
2016	1,800

Thereafter	1,195
Total	$ 17,483

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 10 - COMMITMENTS AND CONTINGENCIES Continued

Other Commitments

During the first quarter of 2012, the Company extended one of its drilling rig contracts in South Texas for an additional nine months. The Company terminated its second contract with no termination penalty and entered into a new contract for a higher performance rig with the same drilling rig contractor for a period of one year. Drilling operations under these two contracts began in early March 2012. Should the Company elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rate being charged to the Company prior to the end of their respective terms, the Company would incur termination obligations. The Company s maximum outstanding aggregate termination obligations under these contracts were approximately $3.7 million at September 30, 2012.

At September 30, 2012, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells, primarily in the Haynesville shale and the Eagle Ford shale. The Company s working interests in these wells are small, and most of these wells were in progress at September 30, 2012. If all of these wells are drilled and completed, the Company s minimum outstanding aggregate commitments at September 30, 2012 for its participation in these wells were approximately $3.6 million, and the Company expects these costs to be incurred in the next twelve months.

Legal Proceedings

Cynthia Fry Peironnet, et al. v. Matador Resources Company. The Company is involved in a dispute over a mineral rights lease involving certain acreage in Louisiana. The dispute regards an extension of the term of a lease in Caddo Parish, Louisiana (the Lease) where the Company has drilled or participated in the drilling of both Cotton Valley and Haynesville shale wells. At issue are the deep rights below the Cotton Valley formation on approximately 1,805 gross acres where the Company has the right to participate for up to a 25% working interest, and also retains a small overriding royalty interest, in Haynesville shale wells drilled in units that include portions of the acreage. The Company s total net revenue and overriding royalty interests in several non-operated Haynesville shale wells previously drilled on this acreage range from approximately 2% to 23%, and only portions of these interests are attributable to this acreage. The sum of the Company s overriding royalty and net revenue interests attributable to this acreage from Haynesville wells previously drilled on this acreage comprises less than one net well.

The plaintiffs brought this claim against the Company on May 15, 2008 in the First Judicial District Court, Caddo Parish, Louisiana (the Trial Court). The plaintiffs sought (i) reformation or rescission of the lease extension, (ii) an accounting for additional royalty, (iii) monetary damages and (iv) attorney s fees. During the pendency of the case in the Trial Court, the Company settled with one lessor who owned a 1/6th undivided interest in the minerals. Since May 2008, the Trial Court has rendered multiple rulings in the favor of the Company, including a unanimous jury verdict in favor of the Company in the fall of 2010. Final judgment of the Trial Court was rendered in favor of Matador on June 6, 2011. On August 1, 2012, the Louisiana Second Circuit of Appeal (the Court of Appeal) affirmed in part and reversed in part the judgment of the Trial Court and remanded the case to the Trial Court for determination of damages. The Court of Appeal affirmed the Trial Court with respect to the 1/6th royalty owner that settled and also affirmed that the Company s lease extension was unambiguous. Nonetheless, the Court of Appeal reformed the lease extension to cover only approximately 169 gross acres, holding that the deep rights covering the remaining 1,636 gross acres had expired. The Court of Appeal denied the Company s motion for rehearing, and the Company and certain other defendants have filed an appeal with the Louisiana Supreme Court.

The Company believes that the facts of the case and the applicable law do not support the Court of Appeal s judgment and it intends to vigorously pursue its rights to have the Trial Court s judgment reinstated. Although the Company does not consider a loss resulting from this dispute to be probable, it is reasonably possible that the Company could incur a loss as a result of the continuing litigation of this matter. The Company currently estimates that a reasonable range of potential loss is zero to $6 million.

Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 10 - COMMITMENTS AND CONTINGENCIES Continued

Other

The Company is a defendant in several other lawsuits encountered in the ordinary course of its business, none of which, in the opinion of management, will have a material adverse impact on the Company s financial position, results of operations or cash flows.

NOTE 11 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company s current accrued liabilities at September 30, 2012 and December 31, 2011 (in thousands).

	September 30, 2012	December 31, 2011
Accrued evaluated and unproved and unevaluated property costs	$ 39,813	$ 18,185
Accrued support equipment and facilities costs	590	216
Accrued cost to issue equity		332
Accrued stock-based compensation	586	2,860
Accrued lease operating expenses	4,506	575
Accrued interest on borrowings under Credit Agreement	43	
Accrued asset retirement obligations	347	334
Other	4,377	2,937
Total accrued liabilities	$ 50,262	$ 25,439

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the nine months ended September 30, 2012 and 2011 (in thousands).

	Nine Months Ended September 30, 2012	2011
Cash paid for interest expense, net of amounts capitalized	$ 442	$ 201
Asset retirement obligations related to mineral properties	405	437
Asset retirement obligations related to support equipment and facilities	54	15
Increase (decrease) in liabilities for oil and natural gas properties capital expenditures	19,067	(3,638)
Increase in liabilities for support equipment and facilities	482	112

Issuance of restricted stock units for Board and advisor services	34	
Issuance of common stock for Board and advisor services	71	125
Decrease in liabilities for accrued cost to issue equity	(332)	(173)
Stock-based compensation expense recognized as liability	(930)	1,254
Transfer of costs to support equipment and facilities from oil and natural gas properties capital expenditures		129
Transfer of inventory from oil and natural gas properties	(91)	(313)

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS -

UNAUDITED - CONTINUED

NOTE 12 - SUBSEQUENT EVENTS

On October 1, 2012, the Company entered into additional costless collar contracts to mitigate its exposure to commodity price risk associated with natural gas on a portion of its future anticipated natural gas production. The following table summarizes these contracts.

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)
Natural Gas	01/01/2013 - 12/31/2013	100,000	3.00	4.95
Natural Gas	01/01/2013 - 12/31/2013	100,000	3.00	4.96
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42

On November 1, 2012, the Company entered into additional swap contracts to mitigate its exposure to commodity price risk associated with natural gas liquids on a portion of its future anticipated natural gas liquids production. The following table summarizes these contracts.

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)
Natural Gasoline	11/01/2012 - 11/30/2012	12,000	2.200
Natural Gasoline	12/01/2012 - 12/31/2012	12,000	2.120
Natural Gasoline	01/01/2013 - 12/31/2013	12,000	2.025

In October and November 2012, the Company borrowed an additional $14 million and $15 million, respectively, under the Credit Agreement to fund a portion of its working capital requirements and capital expenditures. At November 14, 2012, the Company had $135 million in borrowings outstanding under the Credit Agreement, approximately $1.1 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $63.9 million available for additional borrowings.

On November 8, 2012, the Company awarded a total of 73,000 shares of restricted stock to certain employees. Of these 73,000 shares, 13,833 were fully vested as of the grant date; the remaining 59,167 vest between November 2013 and November 2016. The grant date fair value of these awards is approximately $0.6 million.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC, along with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. The Annual Report is accessible on the SEC s website at www.sec.gov and on our website at www.matadorresources.com. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Cautionary Note Regarding Forward-Looking Statements below for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

In this Quarterly Report on Form 10-Q, references to we, our or the Company refer to Matador Resources Company and its subsidiaries before the completion of our corporate reorganization on August 9, 2011 and Matador Holdco, Inc. and its subsidiaries after the completion of our corporate reorganization on August 9, 2011. Prior to August 9, 2011, Matador Holdco, Inc. was a wholly owned subsidiary of Matador Resources Company, now known as MRC Energy Company. Pursuant to the terms of our corporate reorganization, former Matador Resources Company became a wholly owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

Unless the context otherwise requires, the term common stock refers to shares of our common stock after the conversion of our Class B common stock into Class A common stock upon the consummation of our Initial Public Offering on February 7, 2012, as the Class A common stock became the only class of common stock authorized, and the term Class A common stock refers to shares of our Class A common stock prior to the automatic conversion of our Class B common stock into Class A common stock upon the consummation of our Initial Public Offering.

For certain oil and natural gas terms used in this report, please see the Glossary of Oil and Natural Gas Terms included with our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report on Form 10-Q constitute forward-looking statements within the meaning of applicable U.S. securities legislation. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as anticipate, believe, continue, could, estimate, expect, intend, may, might, potential, predict, project, should or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: changes in oil or natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this report and in other documents that we file with or furnish to the SEC, all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves and the present value thereof;
- our technology;
- our cash flows and liquidity;

our financial strategy, budget, projections and operating results;

our oil and natural gas realized prices;

the timing and amount of future production of oil and natural gas;

the availability of drilling and production equipment;

- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- our estimated future reserves and the present value thereof;
- our plans, objectives, expectations and intentions contained in this report that are not historical; and

other factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward- looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements except as required by law.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Our current operations are located primarily in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana and East Texas. We expect the majority of our near-term capital expenditures will focus on increasing our production and reserves from the Eagle Ford shale play. We believe our interests in the Eagle Ford shale play will enable us to create a more balanced commodity portfolio through the drilling of locations that are prospective for oil and liquids. In addition to these primary operating areas, we have acreage positions in Southeast New Mexico and West Texas and in Southwest Wyoming and adjacent areas of Utah and Idaho where we continue to identify new oil and natural gas prospects.

During the first nine months of 2012, our operations were primarily focused on the exploration and development of our Eagle Ford shale properties in South Texas, as we continued executing our plan to significantly increase our oil production and oil reserves during 2012. During the nine months ended September 30, 2012, we completed and began producing oil and natural gas from 18 gross/17.1 net operated and 2 gross/0.4 net non-operated Eagle Ford shale wells. We also completed and began producing natural gas from 21 gross/0.9 net non-operated Haynesville shale wells. As of September 30, 2012, we had also completed and begun producing oil and natural gas from 2 gross/2 net wells completed in the upper Austin Chalk and the lower Austin Chalk/upper Eagle Ford, or Chalkleford, intervals, respectively. We had two contracted drilling rigs operating in South Texas throughout the first nine months of 2012 (except for a brief period near the end of the second quarter where we added a third rig to execute a two-well contract), and almost all of our operated drilling and completion activities were focused on the Eagle Ford shale. At November 14, 2012, we have two contracted drilling rigs operating in South Texas: one in LaSalle County and one in DeWitt County.

In the third quarter of 2012 specifically, our activities were almost entirely focused on our Eagle Ford shale properties. During the three months ended September 30, 2012, we completed and began producing oil and/or natural gas from 6 gross/5.3 net operated and 1 gross/0.2 net non-operated Eagle Ford shale wells. We completed two wells on our Love lease in DeWitt County, two wells on our Northcut lease in LaSalle County, one well on our Martin Ranch lease in LaSalle County and one well on our Sickenius lease in Karnes County. We also completed 2 gross/2 net wells on our Glasscock Ranch lease in Zavala County. These two wells were completed in the upper Austin Chalk and the lower Austin Chalk/upper Eagle Ford, or Chalkleford, intervals, respectively. The two wells on the Love lease began producing in August 2012; the two wells on the Northcut lease and the well on the Sickenius lease began producing in September. The well drilled on the Martin Ranch lease did not begin producing until late September. As a result, these six wells did not contribute fully to our third quarter production volumes.

Our average daily production for the three months ended September 30, 2012 was 8,838 BOE per day, including 3,291 Bbl of oil per day and 33.3 MMcf of natural gas per day, as compared to 6,931 BOE per day, including 465 Bbl of oil per day and 38.8 MMcf of natural gas per day for the three months ended September 30, 2011. Both the average total daily production and the average daily oil production for the third quarter of 2012 were the best quarterly figures in our history. Our average daily oil production of 3,291 Bbl per day during the third quarter of 2012 was an increase of about 5% from an average daily oil production of approximately 3,131 Bbl per day during the second quarter of 2012 and an increase of over seven-fold from an average daily oil production of 465 Bbl per day in the third quarter of 2011. Our average daily production for the nine months ended September 30, 2012 was 8,534 BOE per day, including 2,876 Bbl of oil per day and 33.9 MMcf of natural gas per day, as compared to 7,081 BOE per day, including 414 Bbl of oil per day and 40.0 MMcf of natural gas per day for the nine months ended September 30, 2011. Our total oil production increased almost seven-fold to approximately 788,000 Bbl of oil during the first nine months of 2012 from approximately 113,000 Bbl of oil during the first nine months of 2011. This increased oil production is a direct result of our ongoing drilling operations in the Eagle Ford shale. Oil production comprised approximately 37% and 34% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the three and nine months ending September 30, 2012, respectively, as compared to approximately 7% and 6% of our total production for the three and nine months ended September 30, 2011, respectively.

Our oil and natural gas revenues were approximately $103.3 million, or an increase of about 99%, for the nine months ended September 30, 2012 as compared to $52.0 million for the nine months ended September 30, 2011. Our oil revenues increased almost eight-fold to $81.0 million for the nine months ended September 30, 2012 as compared to $10.5 million for the nine months ended September 30, 2011. Our oil and natural gas revenues of $103.3 million for the first nine months of 2012 were 154% of our total oil and natural gas revenues of $67.0 million reported for all of 2011. Our Adjusted EBITDA increased by approximately $40.3 million to approximately $77.9 million, or an increase of approximately 107%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. This increase in our Adjusted EBITDA is primarily attributable to the increase in our oil production and the associated increase in our oil and natural gas revenues for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011.

Our estimated proved oil reserves increased almost eight-fold to approximately 8.4 million Bbl of oil at September 30, 2012 from approximately 1.1 million Bbl of oil at September 30, 2011, based on the reserves audit by our independent reservoir engineers, Netherland, Sewell & Associates, Inc. At September 30, 2012, we had approximately 20.9 million BOE of estimated total proved reserves, including approximately 8.4 million Bbl of oil and 74.9 Bcf of natural gas, with a PV-10 of $363.6 million and a Standardized Measure of $333.9 million. At September 30, 2012, 61% of our estimated proved reserves were proved developed reserves, 40% of our estimated proved reserves were oil and 60% of our estimated proved reserves were natural gas. At September 30, 2011, based on the reserves audit by our independent reservoir engineers, we had approximately 27.0 million BOE of estimated total proved reserves, including 1.1 million barrels of oil and 155.3 Bcf of natural gas, with a PV-10 of $155.2 million and a Standardized Measure of $143.4 million. At September 30, 2011, 34% of our estimated proved reserves were proved developed reserves, 4% of our estimated proved reserves were oil and 96% of our estimated proved reserves were natural gas.

The unweighted arithmetic average of the first-day-of-the-month natural gas prices was $2.826 per MMBtu for the period from October 2011 to September 2012 and $4.158 per MMBtu for the period from October 2010 to September 2011.

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These average prices were the natural gas prices used to estimate our natural gas reserves at September 30, 2012 and 2011, respectively. As a result of declines in natural gas prices, at June 30, 2012, we removed 97.8 Bcf (or approximately 16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our estimated total proved reserves, most of which were attributable to non-operated properties. No similar reduction to our proved reserves was necessary at September 30, 2012. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time when natural gas prices improve.

During 2012, we intend to allocate 84% of our 2012 capital expenditure budget of $313.0 million to the exploration, development and acquisition of additional interests in the Eagle Ford shale play. Including these anticipated capital expenditures in the Eagle Ford shale, we plan to dedicate about 94% of our 2012 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. At September 30, 2012, we have incurred approximately $237.6 million or about 76% of our 2012 estimated capital expenditures of $313.0 million. This includes approximately $21.2 million incurred to acquire additional leasehold acreage primarily in the Eagle Ford shale near our existing properties and the Delaware Basin in West Texas. During the first nine months of 2012, our drilling and completion costs for new wells have been less than we budgeted, although our costs for production facilities, pipelines and other infrastructure have exceeded our initial estimates. Overall, at September 30, 2012, we are executing our 2012 capital expenditure program largely as planned and remain within our anticipated capital expenditure budget for 2012. While we have budgeted $313.0 million for 2012, the aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results, as well as other opportunities we may encounter during the remainder of 2012.

During the nine months ended September 30, 2012, natural gas prices have declined to their lowest levels in many years, with the NYMEX Henry Hub natural gas futures contract for the earliest delivery date reaching a low of $1.91 per MMBtu in mid-April. Although natural gas prices have rallied in the last several months, reaching a high of $3.32 per MMBtu in late September, we would not expect to drill any operated natural gas wells, except for natural gas wells in specific exploratory projects like the Meade Peak shale in Southwest Wyoming, until natural gas prices improved significantly from their recent levels. In addition, as a result of these low natural gas prices, several of our non-operated Haynesville shale wells were shut in for brief periods or produced less natural gas than we anticipated during the first nine months of 2012 as the operators voluntarily curtailed a portion of the natural gas production from these wells.

As we continue to transition our operations to the Eagle Ford shale play in South Texas, we may face challenges associated with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to transport, process and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure and facilities on our leases throughout the area. We believe we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations. We did not experience difficulties in securing completion, and particularly hydraulic fracturing services, for any wells drilled during the first nine months of 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. We believe that maintaining reliable drilling and completion services and reducing drilling and completion costs will be essential to the successful development of the Eagle Ford shale play.

We did experience temporary pipeline interruptions from time to time during the three and nine months ended September 30, 2012 associated with natural gas production from our Eagle Ford shale wells and elected to either shut in wells for brief periods or flare some of the natural gas we produced. To alleviate most of the pipeline interruptions and capacity constraints we experienced during 2012, effective September 1, 2012, we entered into a natural gas gathering, transportation and processing agreement that includes firm transportation and processing for most of our operated natural gas production in South Texas. The agreement has an initial term of five years. No assurance can be made that this agreement will alleviate these issues and if we were required to shut in our production for long periods of time due to pipeline interruptions, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

During the three months ended September 30, 2012, Matador and its partner finalized commercial arrangements related to the ongoing exploration of the Meade Peak shale. Operations are scheduled to begin in the fourth quarter of 2012 to conduct a horizontal test of the Meade Peak shale. The existing Crawford Federal #1 vertical wellbore was drilled and cored through the Meade Peak shale and then suspended in December 2011. Plans are to re-enter this existing wellbore, plug back to a sufficient depth to sidetrack and drill a horizontal lateral to test the Meade Peak formation. Matador s share of the anticipated costs of this operation will be carried by its partner. Matador and its partner also intend to renew leases that may be available for renewal and may acquire additional leasehold within their area of mutual interest.

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On February 2, 2012, our common stock began trading on the New York Stock Exchange, or NYSE, under the symbol MTDR. Our general and administrative expenses have increased as a result of us operating as a public company. These increased expenses include costs associated with, among other items, legal and accounting support services, filing annual and quarterly reports with the SEC, investor relations activities, directors fees, incremental directors and officers liability insurance costs, transfer and registrar agent fees and expenses associated with compliance with the Sarbanes-Oxley Act and other regulations. In addition, we have increased our staff size and compensation and incurred other ongoing general and administrative expenses necessary to maintain and grow a publicly traded exploration and production company. As a result, we believe that our general and administrative expenses for future periods may continue to increase. Our consolidated financial statements for future periods will reflect these increased expenses and affect the comparability of our financial statements with periods before the completion of our Initial Public Offering.

Initial Public Offering

We closed the Initial Public Offering of our common stock on February 7, 2012 and closed the over-allotment option on March 7, 2012. We issued 12,209,167 shares of common stock and 2,674,167 shares of common stock were sold by the selling shareholders. The shares were sold at a price to the public of $12.00 per share and we received cash proceeds of approximately $136.6 million from this transaction, net of underwriting discounts and commissions. We did not receive any proceeds from the sale of shares by the selling shareholders. The underwriters received underwriting discounts and commissions totaling approximately $9.9 million, and we incurred additional costs of approximately $3.5 million in connection with the offering, which amounted to total fees and costs of approximately $13.4 million. We used $123.0 million of the net proceeds to repay the then outstanding borrowings under our Credit Agreement. We used the remaining net proceeds to fund a portion of our 2012 capital expenditure requirements.

Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at September 30, 2012 and 2011. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC s rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total estimated proved reserves are estimated using a conversion ratio of one Bbl per six Mcf.

	At September 30,(1)	
	2012	**2011**
Estimated Proved Reserves Data:(2)		
Estimated proved reserves:		
Oil (MBbl)	8,411	1,083
Natural Gas (Bcf)	74.9	155.3
Total (MBOE) (3)	20,894	26,971
Estimated proved developed reserves:		
Oil (MBbl)	3,783	519
Natural Gas (Bcf)	53.4	52.7
Total (MBOE)	12,686	9,294
Percent developed	60.7%	34.5%
Estimated proved undeveloped reserves:		
Oil (MBbl)	4,628	565
Natural Gas (Bcf)	21.5	102.7
Total (MBOE)	8,208	17,677

PV-10[4] (in millions)	$ 363.6	$ 155.2
Standardized Measure[5] (in millions)	$ 333.9	$ 143.4

(1) Numbers in table may not total due to rounding.

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(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from October 2011 to September 2012 were $91.48 per Bbl for oil and $2.826 per MMBtu for natural gas and for the period from October 2010 to September 2011 were $91.00 per Bbl for oil and $4.158 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead.

(3) Thousands of barrels of oil equivalent, estimated using a conversion ratio of one Bbl per six Mcf.

(4) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies properties without regard to the specific tax characteristics of such entities. Our PV-10 at September 30, 2012 and 2011 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at September 30, 2012 and 2011 were, in millions, $29.7 and $11.8, respectively.

(5) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

Our estimated proved oil and natural gas reserves decreased from approximately 27.0 million BOE at September 30, 2011 to approximately 20.9 million BOE at September 30, 2012, reflecting primarily the decrease in our proved undeveloped natural gas reserves from 102.7 Bcf at September 30, 2011 to 21.5 Bcf at September 30, 2012. The unweighted arithmetic average of the first-day-of-the-month natural gas prices was $2.826 per MMBtu for the period from October 2011 to September 2012 and $4.158 per MMBtu for the period from October 2010 to September 2011. These average prices were the natural gas prices used to estimate our natural gas reserves at September 30, 2012 and 2011, respectively. As a result of the decline in natural gas prices, at June 30, 2012, we removed 97.8 Bcf (or approximately 16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our estimated total proved reserves, most of which were attributable to non-operated properties. No additional reduction to our reserves was necessary at September 30, 2012. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells these natural gas volumes remain available to be developed by us or the operator at a future time when natural gas prices improve.

Our estimated proved oil reserves increased almost eight-fold to approximately 8.4 million Bbl at September 30, 2012 from approximately 1.1 million Bbl at September 30, 2011. This increase is attributable to proved oil reserves added as a result of our drilling operations in the Eagle Ford shale in South Texas. The PV-10 of our proved oil and natural gas reserves more than doubled to $363.6 million at September 30, 2012 from $155.2 million at September 30, 2011. Our proved developed and proved undeveloped oil reserves increased to 3.8 million Bbl and 4.6 million Bbl, respectively, at September 30, 2012, compared to 519,000 Bbl and 565,000 Bbl, respectively, at September 30, 2011. Our estimated total proved oil and natural gas reserves at September 30, 2012 were approximately 61% proved developed reserves and were made up of approximately 40% oil and 60% natural gas. Our estimated total proved reserves at September 30, 2011 were approximately 34% proved developed reserves and were made up of approximately 4% oil and 96% natural gas.

During the nine months ended September 30, 2012, natural gas prices have declined to their lowest levels in many years, with the NYMEX Henry Hub natural gas futures contract for the earliest delivery date reaching a low of $1.91 per MMBtu in mid-April. Although natural gas prices have rallied in the last several months, reaching a high of $3.32 per MMBtu in late September, the unweighted arithmetic average of the first-day-of-the month prices for the previous 12 months used to estimate natural gas reserves continued its decline during the third quarter of 2012 and could continue to do so in future periods. Should this occur, it may become necessary for us to remove the remaining Haynesville shale proved undeveloped reserves (approximately 14 Bcf) from our estimated total proved reserves in a future period. This could, in turn, result in additional impairment of the carrying value of our oil and natural gas properties on our balance sheet due to the full-cost ceiling limitation or a reduction in our borrowing base under the Credit Agreement.

There have been no changes to the technology we used to establish reserves or to our internal control over the reserves estimation process from those set forth in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

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Critical Accounting Policies

There have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

The Company has elected not to take advantage of the extended transition period provided in Securities Act of 1933 Section 7(a)(2)(B) for complying with new or revised accounting standards.

Recent Accounting Pronouncements

There have been no additional recent accounting pronouncements impacting our financial reporting from those set forth in the Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Results of Operations

Revenues

The following table summarizes our revenues and production data for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012 (Unaudited)	2011 (Unaudited)	2012 (Unaudited)	2011 (Unaudited)
Operating Data:				
Revenues (in thousands):				
Oil	$ 30,074	$ 3,678	$ 81,047	$ 10,468
Natural gas	7,934	13,769	22,203	41,541
Total oil and natural gas revenues	38,008	17,447	103,250	52,009
Realized gain on derivatives	3,371	1,435	11,147	4,237
Unrealized (loss) gain on derivatives	(12,993)	2,870	(1,149)	1,534
Total revenues	$ 28,386	$ 21,752	$ 113,248	$ 57,780
Net Production Volumes:				
Oil (MBbl)	303	43	788	113
Natural gas (Bcf)	3.1	3.6	9.3	10.9
Total oil equivalents (MBOE)(1),(2)	813	638	2,338	1,933
Average net daily production (BOE/d)(2)	8,838	6,931	8,534	7,081
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$ 100.56	$ 85.92	$ 104.25	$ 92.71
Oil, without realized derivatives (per Bbl)	$ 99.33	$ 85.92	$ 102.86	$ 92.71
Natural gas, with realized derivatives (per Mcf)	$ 3.57	$ 4.26	$ 3.47	$ 4.19
Natural gas, without realized derivatives (per Mcf)	$ 2.59	$ 3.86	$ 2.39	$ 3.80

(1) Thousands of barrels of oil equivalent.
(2) Estimated using a conversion ratio of one Bbl per six Mcf.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $20.6 million to approximately $38.0 million, or an increase of about 118%, for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. This increase in oil and natural gas revenues reflects an increase in our oil revenues of $26.4 million and a decrease in our natural gas revenues of $5.8 million for the three months ended September 30, 2012 as compared to the comparable period in 2011. Our oil revenues increased over eight-fold to $30.1 million for the three months ended September 30, 2012 as compared to $3.7 million for the three months ended September 30, 2011. Our oil production also increased over seven-fold to approximately 303,000 Bbl of oil, or about 3,291 Bbl of oil per day, from approximately 43,000 Bbl of oil, or about 465 Bbl of oil per day, during the comparable periods due to our drilling operations in the Eagle

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Ford shale. A portion of this increase in oil revenue also reflects a somewhat higher weighted average oil price of $99.33 per Bbl realized during the three months ended September 30, 2012 as compared to a weighted average oil price of $85.92 per Bbl realized during the three months ended September 30, 2011. The decrease in our natural gas revenues reflects a decline in our natural gas production by about 14% to approximately 3.1 Bcf for the three months ended September 30, 2012 as compared to approximately 3.6 Bcf for the three months ended September 30, 2011. This decline in natural gas production is due to several factors, including (i) the natural decline in natural gas production primarily from our existing Cotton Valley and Haynesville shale wells in Northwest Louisiana and East Texas, coupled with our decision not to drill any operated Haynesville shale wells in 2012, (ii) the voluntary curtailment of natural gas production from some of our non-operated Haynesville shale wells in Northwest Louisiana and (iii) the flaring of a portion of the natural gas produced from our newly completed Eagle Ford shale wells in South Texas as a result of gas pipeline constraints and awaiting the installation of permanent production facilities. This decrease in natural gas revenues also results from a significantly lower weighted average natural gas price of $2.59 per Mcf realized during the three months ended September 30, 2012 as compared to a weighted average natural gas price of $3.86 per Mcf realized during the three months ended September 30, 2011.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased by approximately $1.9 million to $3.4 million for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. For the three months ended September 30, 2012, we realized a gain of approximately $3.0 million on our natural gas derivative contracts, and we realized a gain of approximately $0.4 million on our oil derivative contracts We realized an average gain of $1.30 per MMBtu hedged on all of our open natural gas costless collar contracts during the three months ended September 30, 2012 as compared to an average gain of $0.65 per MMBtu hedged on all of our open natural gas costless collar contracts during the three months ended September 30, 2011. Our total natural gas volumes hedged for the three months ended September 30, 2012 were also approximately 4% higher than the total natural gas volumes hedged for the same period in 2011. The realized gain from our open oil costless collar contracts resulted primarily from a decline in oil prices during the month of July 2012. We realized an average gain of $1.04 per Bbl hedged on all of our open oil costless collar contracts during the three months ended September 30, 2012. We had no open oil costless collar contracts during the three months ended September 30, 2011.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $13.0 million for the three months ended September 30, 2012 as compared to an unrealized gain on derivatives of $2.9 million for the three months ended September 30, 2011. During the period from June 30, 2012 to September 30, 2012, the net fair value of our open oil and natural gas costless collar contracts and our open natural gas liquids swap contracts decreased from approximately $21.1 million to approximately $8.1 million, resulting in an unrealized loss on derivatives of approximately $13.0 million for the three months ended September 30, 2012. During the three months ended September 30, 2012, the net fair value of our open oil costless collar contracts decreased by approximately $9.0 million primarily due to an increase in oil prices during the third quarter of 2012. During the three months ended September 30, 2012, the net fair value of our open natural gas costless collar contracts decreased by approximately $4.0 million in large part due to the gains realized on these contracts, combined with an increase in natural gas prices during the third quarter of 2012. During the three months ended September 30, 2012, we entered into various new natural gas liquids swap contracts which had a net fair value of approximately $45,000 as of the end of the period. During the period from June 30, 2011 to September 30, 2011, the net fair value of our open natural gas costless collar contracts increased from $2.8 million to $5.7 million, resulting in an unrealized gain on derivatives of $2.9 million for the three months ended September 30, 2011. We had no open oil costless collar or natural gas liquids swap contracts during the three months ended September 30, 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $51.2 million to approximately $103.3 million, or an increase of about 99%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. This increase in oil and natural gas revenues reflects an increase in our oil revenues of $70.6 million and a decrease in our natural gas revenues of $19.3 million for the nine months ended September 30, 2012 as compared to the comparable period in 2011. Our oil revenues increased almost eight-fold to $81.0 million for the nine months ended September 30, 2012 as compared to $10.5 million for the nine months ended September 30, 2011. Our oil production increased almost seven-fold to approximately 788,000 Bbl of oil, or about 2,876 Bbl of oil per day, from approximately 113,000 Bbl of oil, or about 414 Bbl of oil per day, during the comparable periods due to our drilling operations in the Eagle Ford shale. A portion of this increase in oil revenue also reflects a somewhat higher weighted average oil price of $102.86 per Bbl realized during the first nine months of 2012 as compared to a weighted average oil price of $92.71 per Bbl realized during the first nine months of 2011. The decrease in our natural gas revenues reflects a decline in our natural gas production by about 15% to approximately 9.3 Bcf for the nine months ended September 30, 2012 as compared to approximately 10.9 Bcf for the nine months ended September 30, 2011. This decline in natural gas production is due to several factors, including (i) the natural decline in natural gas production primarily from our existing Cotton Valley and Haynesville shale wells in Northwest

Louisiana and East Texas, coupled with our decision not to drill any operated Haynesville shale wells in 2012, (ii) the voluntary curtailment of natural gas production from some of our non-operated Haynesville shale wells in Northwest Louisiana and (iii) the flaring of a portion of the natural gas produced from our newly completed Eagle Ford shale wells in South Texas as a result of gas pipeline constraints and awaiting the installation of permanent production facilities. This decrease in natural gas revenues also results from a significantly lower weighted average natural gas price of $2.39 per Mcf realized during the first nine months of 2012 as compared to a weighted average natural gas price of $3.80 per Mcf realized during the first nine months of 2011.

Realized gain (loss) on derivatives. Our realized gain on derivatives increased by approximately $6.9 million to $11.1 million for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. For the nine months ended September 30, 2012, we realized a gain of approximately $10.0 million on our natural gas derivative contracts, and we realized a gain of approximately $1.1 million on our oil derivative contracts. As a result of declining natural gas prices between the comparable periods, we realized an average gain of approximately $1.70 per MMBtu hedged on all of our open natural gas costless collar contracts during the nine months ended September 30, 2012 as compared to $0.91 per MMBtu hedged on all of our open natural gas costless collar contracts during the nine months ended September 30, 2011. Our total natural gas volumes hedged for the nine months ended September 30, 2012 were also approximately 26% higher than the total natural gas volumes hedged for the same period in 2011. We realized an average gain of $1.33 per Bbl hedged on all of our open oil costless collar contracts during the nine months ended September 30, 2012. We had no open oil costless collar contracts during the nine months ended September 30, 2011.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $1.2 million for the nine months ended September 30, 2012 as compared to an unrealized gain of $1.5 million for the nine months ended September 30, 2011. During the period from December 31, 2011 to September 30, 2012, the net fair value of our open oil and natural gas costless collar contracts and natural gas liquids swaps decreased from approximately $9.3 million to approximately $8.1 million, resulting in an unrealized loss on derivatives of approximately $1.2 million for the nine months ended September 30, 2012. During the nine months ended September 30, 2012, the net fair value of our open oil costless collar contracts increased by approximately $6.2 million primarily due to a decrease in oil prices at September 30, 2012 compared to December 31, 2011. During the nine months ended September 30, 2012, the net fair value of our open natural gas costless collar contracts decreased by $7.4 million due primarily to the gains realized on these contracts during the first nine months of 2012. During the first nine months of 2012, we also entered into additional natural gas costless collar contracts. During the first nine months of 2012, we entered into various natural gas liquids swap contracts which had a net fair value of approximately $45,000 as of the end of the period. During the period from December 31, 2010 to September 30, 2011, the net fair value of our open natural gas costless collar contracts increased from $4.1 million to $5.6 million, resulting in an unrealized gain on derivatives of $1.5 million for the nine months ended September 30, 2011. We had no open oil costless collar or natural gas liquids swap contracts during the nine months ended September 30, 2011.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated. As a result of the increasing significance of our oil production, all per unit expenses are presented as per BOE as compared to per Mcfe in prior reporting periods.

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(In thousands, except expenses per BOE)	Three Months Ended September 30, 2012 (Unaudited)	Three Months Ended September 30, 2011 (Unaudited)	Nine Months Ended September 30, 2012 (Unaudited)	Nine Months Ended September 30, 2011 (Unaudited)
Expenses:				
Production taxes and marketing	$ 2,822	$ 1,848	$ 7,605	$ 4,801
Lease operating	6,491	2,065	17,511	5,639
Depletion, depreciation and amortization	21,680	7,288	52,799	22,578
Accretion of asset retirement obligations	59	61	170	158
Full-cost ceiling impairment	3,596		36,801	35,673
General and administrative	3,439	4,207	11,321	9,919
Total expenses	38,087	15,469	126,207	78,768
Operating (loss) income	(9,701)	6,283	(12,959)	(20,988)
Other income (expense):				
Net loss on asset sales and inventory impairment			(60)	
Interest expense	(144)	(171)	(453)	(461)
Interest and other income	55	82	157	248
Total other expense	(89)	(89)	(356)	(213)
(Loss) income before income taxes	(9,790)	6,194	(13,315)	(21,201)
Total income tax benefit	(593)		(1,242)	(6,952)
Net (loss) income	$ (9,197)	$ 6,194	$ (12,073)	$ (14,249)
Expenses per BOE:				
Production taxes and marketing	$ 3.47	$ 2.90	$ 3.25	$ 2.48
Lease operating	$ 7.98	$ 3.24	$ 7.49	$ 2.92
Depletion, depreciation and amortization	$ 26.66	$ 11.43	$ 22.58	$ 11.68
General and administrative	$ 4.23	$ 6.60	$ 4.84	$ 5.13

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $1.0 million to approximately $2.8 million, or an increase of approximately 53%, for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. The increase in our production taxes and marketing expenses primarily reflects the increase in our total oil and natural gas revenues by 118% during the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. The majority of this increase was attributable to production taxes and marketing expenses associated with the large increase in oil production resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 37% oil and 63% natural gas for the three months ended September 30, 2012 as compared to approximately 7% oil and 93% natural gas during the same period in 2011. On a unit-of-production basis, our production taxes and marketing expenses increased by 20% to $3.47 per BOE for the three months ended September 30, 2012 as compared to $2.90 per BOE for the three months ended September 30, 2011.

Lease operating expenses. Our lease operating expenses increased by approximately $4.4 million to approximately $6.5 million, or an increase of approximately three-fold for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. Our total oil and natural gas production increased by about 28% from approximately 638,000 BOE during the three months ended September 30, 2011 to approximately 813,000 BOE during the three months ended September 30, 2012, but our oil production increased over seven-fold from approximately 43,000 Bbl to approximately 303,000 Bbl during these respective periods. The increase in lease operating expenses was primarily attributable to the large increase in our oil production as a result of our ongoing drilling and completion operations in the Eagle Ford shale in 2012. In addition, oil production comprised 37% of our total production during the three months ended September 30, 2012 as compared to only 7% of our total production during the same period in 2011, resulting in higher overall lease operating expenses during the second quarter of 2012. During the three months ended September 30, 2012, we completed and initiated oil and natural gas production from 6 gross/5.3 net wells in the Eagle Ford shale (plus 2 gross/2 net Austin Chalk/ Chalkleford wells), some of which were on properties where new production facilities were being installed or natural gas pipelines were awaiting completion. While these new facilities were being installed and tested, much of the oil and natural gas was produced through rental test equipment monitored by 24-hour contract personnel, resulting in higher operating costs

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from these properties during the three months ended September 30, 2012 than we anticipate going forward now that the permanent production facilities and natural gas pipeline connections on most of these properties are complete. As we continue to drill new properties in the Eagle Ford shale throughout the remainder of 2012, however, we also expect to produce new wells on these properties through rental test equipment until more permanent facilities can be constructed and installed. Our lease operating expenses per unit of production increased 146% to $7.98 per BOE for the three months ended September 30, 2012 as compared to $3.24 per BOE for the three months ended September 30, 2011.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $14.4 million to $21.7 million, or an increase of about three-fold, for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $26.66 per BOE for the three months ended September 30, 2012, or an increase of about 133%, from $11.43 per BOE for the three months ended September 30, 2011. This increase in our depletion, depreciation and amortization expenses was primarily attributable to the decrease in our total proved oil and natural gas reserves to 20.9 million BOE at September 30, 2012 as compared to 27.0 million BOE at September 30, 2011. As noted previously, as a result of declines in natural gas prices during 2012, we removed 97.8 Bcf (or approximately 16.3 million BOE) in proved undeveloped Haynesville shale natural gas reserves from our total proved reserves at June 30, 2012. This increase in depletion, depreciation and amortization expense was also partially due to the increase of approximately 28% in our total oil and natural gas production to approximately 813,000 BOE during the three months ended September 30, 2012 as compared to approximately 638,000 BOE during the three months ended September 30, 2011, as well as to the higher drilling and completions costs on a per BOE basis associated with oil reserves added in the Eagle Ford shale in South Texas as compared with our Haynesville shale natural gas assets in Northwest Louisiana.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses remained essentially unchanged at approximately $59,000 and $61,000 for the three months ended September 30, 2012 and 2011, respectively. This item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. At September 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. As a result, we recorded an impairment charge of $3.6 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $1.3 million, which is reflected in our operating expenses for the three months ended September 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices. No impairment to the net capitalized costs of our oil and natural gas properties and no corresponding charge to our operating expenses was recorded for the three months ended September 30, 2011.

General and administrative. Our general and administrative expenses decreased by $0.8 million to $3.4 million, or a decrease of about 18%, for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. Our general and administrative expenses decreased by 36% on a unit-of-production basis to $4.23 per BOE for the three months ended September 30, 2012 as compared to $6.60 per BOE for the three months ended September 30, 2011. The decrease in our general and administrative expenses was attributable primarily to decreased stock based compensation expense, partially offset by increased compensation, accounting, legal and other administrative expenses, much of which is associated with becoming a public company in February 2012.

Interest expense. For the three months ended September 30, 2012, we incurred total interest expense of approximately $0.5 million. We capitalized $0.4 million of the interest expense on the outstanding borrowings under our Credit Agreement to certain qualifying projects and expensed the remaining $0.1 million to operations for the three months ended September 30, 2012. During the three months ended September 30, 2012, we borrowed $46.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. Our total outstanding borrowings at September 30, 2012 were $106.0 million, and the effective interest rate on these borrowings was approximately 5.3% per annum as the borrowings were outstanding as a base rate advance. In early October, the borrowings were converted to a Eurodollar-based rate advance and bore interest at an effective rate of approximately 3.3% per annum. At September 30, 2011, we had outstanding borrowings of $85.0 million under our Credit Agreement and incurred total interest expense of approximately $0.6 million. We capitalized $0.4 million of our interest expense on certain qualifying projects and expensed the remaining $0.2 million to operations for the three months ended September 30, 2011.

Interest and other income. Our interest and other income decreased by approximately $27,000 to approximately $55,000, or a decrease of about 33%, for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. The decrease in our interest and other income was due primarily to a decrease in the natural gas transportation income received from third parties during the three months ended September 30, 2012 as compared to the three months

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ended September 30, 2011. On the whole, this item is an insignificant component of our overall income. Our cash and cash equivalents and certificates of deposit decreased to approximately $4.4 million at September 30, 2012 from approximately $9.9 million at September 30, 2011.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $0.6 million for the three months ended September 30, 2012 as compared to a total income tax provision of approximately zero for the three months ended September 30, 2011. We had a net loss for the three months ended September 30, 2012. The Company established a valuation allowance of approximately $2.4 million at September 30, 2012, due to uncertainties regarding the future realization of its deferred tax assets. The Company established a valuation allowance at March 31, 2011 and retained a valuation allowance of approximately $0.8 million at September 30, 2011, due to uncertainties regarding the future realization of its deferred tax assets. As a result, there was no deferred income tax expense recorded for the three months ended September 30, 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $2.8 million to approximately $7.6 million, or an increase of approximately 58%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. The increase in our production taxes and marketing expenses primarily reflects the increase in our total oil and natural gas revenues of 99% during the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. The majority of this increase was attributable to production taxes and marketing expenses associated with the large increase in oil production resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 34% oil and 66% natural gas for the nine months ended September 30, 2012 as compared to approximately 6% oil and 94% natural gas during the same period in 2011. On a unit-of-production basis, our production taxes and marketing expenses increased by 31% to $3.25 per BOE for the nine months ended September 30, 2012 as compared to $2.48 per BOE for the nine months ended September 30, 2011.

Lease operating expenses. Our lease operating expenses increased by approximately $11.9 million to approximately $17.5 million, or an increase of approximately three-fold for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. Our total oil and natural gas production increased 21% from approximately 1.9 million BOE to approximately 2.3 million BOE, but our oil production increased almost seven-fold from approximately 113,000 Bbl to approximately 788,000 Bbl during these respective periods. The increase in lease operating expenses was primarily attributable to the large increase in our oil production as a result of our ongoing drilling and completion operations in the Eagle Ford shale in 2012. In addition, oil production comprised 34% of our total production during the nine months ended September 30, 2012 as compared to only 6% of our total production during the same period in 2011, resulting in higher overall lease operating expenses during the first nine months of 2012. During the nine months ended September 30, 2012, we completed and initiated oil and natural gas production from 18 gross/17.1 net operated Eagle Ford wells (plus 2 gross/2 net Austin Chalk/ Chalkleford wells), the majority on properties where new production facilities or natural gas pipelines were awaiting construction. While these new facilities were being installed and tested, much of the oil and natural gas was produced through rental test equipment monitored by 24-hour contract personnel, resulting in higher operating costs from these properties during the nine months ended September 30, 2012 than we anticipate going forward now that the permanent production facilities and natural gas pipeline connections on most of these properties are complete. As we continue to drill new properties in the Eagle Ford shale throughout the remainder of 2012, however, we also expect to produce new wells on these properties through rental test equipment until more permanent facilities can be constructed and installed. Our lease operating expenses per unit of production increased 157% to $7.49 per BOE for the nine months ended September 30, 2012 as compared to $2.92 per BOE for the nine months ended September 30, 2011.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $30.2 million to $52.8 million, or an increase of about 134%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $22.58 per BOE for the nine months ended September 30, 2012, or an increase of about 93%, from $11.68 per BOE for the nine months ended September 30, 2011. As noted previously, as a result of declines in natural gas prices during 2012, we removed 97.8 Bcf (or approximately 16.3 million BOE) in proved undeveloped Haynesville shale natural gas reserves from our total proved reserves at June 30, 2012. This increase in our depletion, depreciation and amortization expenses was primarily attributable to the decrease in our total proved oil and natural gas reserves to 20.9 million BOE at September 30, 2012 as compared to 27.0 million BOE at September 30, 2011. This increase in our depletion, depreciation and amortization expenses was also partially attributable to an increase of approximately 21% in our total oil and natural gas production to approximately 2.3 million BOE during the nine months ended September 30, 2012 as compared to approximately 1.9 million BOE during the nine months ended September 30, 2011, as well as to the higher drilling and completions costs on a per BOE basis associated with oil reserves added in the Eagle Ford shale in South Texas as compared with our Haynesville shale natural gas assets in Northwest Louisiana.

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Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $12,000 to approximately $170,000, or an increase of about 8%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. The increase in our accretion of asset retirement obligations was due primarily to the addition of new wells through our drilling of operated wells and our participation in the drilling of non-operated wells, although, on the whole, this item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. At June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. As a result, we recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $11.9 million, which is reflected in our operating expenses for the nine months ended September 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices, resulting in the removal of 97.8 Bcf (or approximately 16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. At September 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. As a result, we recorded an impairment charge of $3.6 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $1.3 million at September 30, 2012, which is also reflected in our operating expenses for the nine months ended September 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices. During the first quarter of 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million, which is reflected in our operating expenses for the nine months ended September 30, 2011.

General and administrative. Our general and administrative expenses increased by $1.4 million to $11.3 million, or an increase of about 14%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. Our general and administrative expenses decreased by 6% on a unit-of-production basis to $4.84 per BOE for the nine months ended September 30, 2012 as compared to $5.13 per BOE for the nine months ended September 30, 2011. The increase in our general and administrative expenses was attributable primarily to increased compensation, accounting, legal and other administrative expenses, much of which is associated with becoming a public company in February 2012.

Net loss on asset sales and inventory impairment. During the nine months ended September 30, 2012, we sold some of our lease and well equipment inventory for approximately $60,000 less than the previously recorded fair value and recognized this loss upon the sale. No such sale or impairment of lease and well equipment inventory occurred during the same period in 2011.

Interest expense. For the nine months ended September 30, 2012, we incurred total interest expense of approximately $1.5 million. We capitalized approximately $1.0 million of our interest expense on certain qualifying projects for the nine months ended September 30, 2012 and expensed the remaining $0.5 million to operations. On February 8, 2012, we repaid our borrowings then outstanding of $123.0 million under our Credit Agreement using a portion of the net proceeds received from our Initial Public Offering. From March 1 through September 30, 2012, we borrowed $106.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. Our total outstanding borrowings at September 30, 2012 were $106.0 million, and the effective interest rate on these borrowings was approximately 5.3% per annum as the borrowings were outstanding as a base rate advance. In early October, the borrowings were converted to a Eurodollar-based rate advance and bore interest at an effective rate of approximately 3.3%. At September 30, 2011, we had borrowings of $85.0 million under our Credit Agreement and we incurred total interest expense of approximately $1.2 million for the nine months ended September 30, 2011. We capitalized $0.7 million of our interest expense on certain qualifying projects and expensed the remaining $0.5 million to operations for the nine months ended September 30, 2011.

Interest and other income. Our interest and other income decreased by approximately $91,000 to approximately $157,000, or a decrease of about 37%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. The decrease in our interest and other income was due primarily to a decrease in the natural gas transportation income received from third parties during the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. On the whole, this item is an insignificant component of our overall income. Our cash and cash equivalents and certificates of deposit decreased to approximately $4.4 million at September 30, 2012 from approximately $9.9 million at September 30, 2011.

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Total income tax provision (benefit). We recorded a total income tax benefit of approximately $1.2 million for the nine months ended September 30, 2012 as compared to a total income tax benefit of approximately $7.0 million for the nine months ended September 30, 2011. During the nine months ended September 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.6 million. We recorded an impairment charge of $36.8 million to the net capitalized costs of our oil and natural gas properties and a deferred tax credit of $13.2 million, which was partially offset primarily by an increase in the deferred tax liability related to our unrealized gain on derivatives, resulting in the income tax benefit recorded for the nine months ended September 30, 2012. During the nine months ended September 30, 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million. We had a net loss in each period for the nine months ended September 30, 2012 and 2011.

Liquidity and Capital Resources

Prior to the consummation of our Initial Public Offering on February 7, 2012, our primary sources of liquidity were capital contributions from private investors, our cash flows from operations, borrowings under our Credit Agreement and the proceeds from a significant sale of a portion of our assets in 2008. Our primary use of capital has been, and will continue to be during 2012 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including equity and debt financings, additional borrowings and joint venture partners on some of our properties, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

At September 30, 2012, we had cash and cash equivalents and certificates of deposits totaling approximately $4.4 million, the borrowing base under our Credit Agreement was $200.0 million and we had $106.0 million of outstanding long-term borrowings and approximately $1.1 million in outstanding letters of credit. These borrowings bore interest at an effective interest rate of approximately 5.3% per annum as the borrowings were outstanding as a base rate advance. In early October, the borrowings were converted to a Eurodollar-based rate advance and bore interest at an effective rate of approximately 3.3%. In October and November 2012, we borrowed an additional $14.0 million and $15.0 million, respectively, under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At November 14, 2012, we had $135.0 million of outstanding long-term borrowings and approximately $1.1 million in outstanding letters of credit.

On September 28, 2012, we entered into the third amended and restated Credit Agreement, which increased the maximum facility amount to $500.0 million from $400.0 million and increased the borrowing base to $200.0 million from $125.0 million. As a result of this increased borrowing capacity, together with our anticipated increases in oil production and any borrowing base increases resulting from our anticipated growth in proved oil reserves, we expect to have sufficient cash flows from operations and future borrowing capacity under our Credit Agreement to fund the remainder of our 2012 capital expenditure budget and our capital expenditure requirements for 2013. Funding for future acquisitions of interests and acreage and our capital expenditure requirements for subsequent years may require additional sources of financing, which may not be available.

A majority of our increase in cash flows during the nine months ended September 30, 2012 has come from our exploration activities on unproved properties at December 31, 2011 in the Eagle Ford shale play. If our ongoing exploration activities are unsuccessful or result in less cash flows than anticipated going forward, we may seek additional sources of capital, including through borrowings under our Credit Agreement (assuming availability under our borrowing base). In addition to future borrowings under our Credit Agreement, we may also seek to raise additional funds by selling shares of our common stock or securities convertible or exercisable into our common stock (including debt securities or other preferential securities) in the public market or otherwise or seek joint venture partners on some of our properties. It is likely that any such sales of securities would dilute the ownership interest of our existing shareholders. It is also possible that, to the extent we are not able to obtain additional sources of liquidity, we may modify our planned capital expenditures budget for 2013 and subsequent years accordingly. Exploration activities are subject to a number of risks and uncertainties that could impact our ability to sufficiently increase our reserves, cash flows from operations and borrowing base under our Credit Agreement.

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Our cash flows for the nine months ended September 30, 2012 and 2011 are presented below:

	Nine Months Ended September 30,	
	2012	2011
(In thousands)	(Unaudited)	(Unaudited)
Net cash provided by operating activities	$ 80,325	$ 34,443
Net cash used in investing activities	(216,930)	(107,772)
Net cash provided by financing activities	130,499	60,038
Net change in cash and cash equivalents	(6,106)	(13,291)
Adjusted EBITDA(1)	$ 77,894	$ 37,550

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Non-GAAP Financial Measures below.

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by approximately $45.9 million to $80.3 million for the nine months ended September 30, 2012 as compared to net cash provided by operating activities of $34.4 million for the nine months ended September 30, 2011. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $77.3 million for the nine months ended September 30, 2012 from $37.1 million for the nine months ended September 30, 2011. This increase is primarily attributable to the almost seven-fold increase in our oil production to approximately 788,000 Bbl from approximately 113,000 Bbl during the respective periods. A portion of the increase in net cash provided by operating activities also reflects the higher average oil price of $102.86 per Bbl realized during the nine months ended September 30, 2012 as compared to an average oil price of $92.71 per Bbl realized during the nine months ended September 30, 2011. Our accounts payable and accrued liabilities increased to approximately $67.6 million at September 30, 2012 from approximately $21.4 million at September 30, 2011 due to our increased operating activity in South Texas. Our accounts receivable increased to approximately $21.9 million at September 30, 2012 from approximately $14.1 million at September 30, 2011, primarily due to our increased operating activity in South Texas.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by approximately $109.1 million to $216.9 million for the nine months ended September 30, 2012 from $107.8 million for the nine months ended September 30, 2011. This increase in net cash used in investing activities is almost entirely attributable to the increase in our oil and natural gas properties capital expenditures for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. Our oil and natural gas properties capital expenditures for the nine months ended September 30, 2012 were primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play in South Texas.

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipated investing $313.0 million in capital for acquisition, exploration and development activities in 2012 as follows:

	Amount (in millions)
Exploration and development drilling and associated infrastructure	$ 284.5
Leasehold acquisition	24.0
Other capital expenditures, 2-D and 3-D seismic data and recompletions of existing wells	4.5

Total	$ 313.0

At September 30, 2012, we have incurred approximately $237.6 million or about 76% of our 2012 estimated capital expenditures of $313.0 million. This includes approximately $21.2 million incurred to acquire additional leasehold acreage primarily in the Eagle Ford shale near our existing properties and in the Delaware Basin in West Texas. During the first nine months of 2012, our drilling and completion costs for new wells have been less than we budgeted, although our costs for production facilities, pipelines and other infrastructure have exceeded our initial estimates. Overall, at September 30, 2012, we are executing our 2012 capital expenditure program largely as planned and remain within our anticipated capital expenditure budget for 2012. While we have budgeted $313.0 million for 2012, the aggregate amount of capital we will expend may fluctuate materially based on market conditions and our drilling results, as well as other opportunities we may encounter during the remainder of 2012.

For further information regarding our anticipated capital expenditure budget in 2012, see Business General in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC. Our 2012 capital expenditures may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline or costs increase significantly, we could defer a significant portion of our anticipated capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and drilling activities, contractual obligations and other factors both within and outside our control.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $130.5 million for the nine months ended September 30, 2012 as compared to net cash provided by financing activities of $60.0 million for the nine months ended September 30, 2011. The net cash provided by financing activities for the nine months ended September 30, 2012 was principally attributable to the total proceeds from the Initial Public Offering of $146.5 million and total incremental borrowings of $116.0 million during the period, offset by the costs of the offering of $11.6 million incurred during the period and by the repayment of $123.0 million in borrowings during the period. We also received approximately $2.7 million from the exercise of stock options during the nine months ended September 30, 2012. The net cash provided by financing activities for the nine months ended September 30, 2011 was primarily attributable to $60.0 million in borrowings under the Credit Agreement, proceeds of $0.8 million from the exercise of stock options and $0.6 million received from the issuance of common stock, offset by $1.2 million in costs to issue equity and payment of dividends on Class B common stock of $0.2 million.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash, stock-based compensation expense, including stock option and grant expense and restricted stock and restricted stock units expense and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

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(In thousands)	Nine Months Ended September 30, 2012	2011
Unaudited Adjusted EBITDA reconciliation to Net Loss:		
Net loss	$ (12,073)	$ (14,249)
Interest expense	453	461
Total income tax benefit	(1,242)	(6,952)
Depletion, depreciation and amortization	52,799	22,578
Accretion of asset retirement obligations	170	158
Full-cost ceiling impairment	36,801	35,673
Unrealized loss (gain) on derivatives	1,149	(1,534)
Stock option and grant expense	(585)	1,379
Restricted stock and restricted stock units expense	362	36
Net loss on asset sales and inventory impairment	60	
Adjusted EBITDA	$ 77,894	$ 37,550

(In thousands)	Nine Months Ended September 30, 2012	2011
Unaudited Adjusted EBITDA reconciliation to Net Cash provided by Operating Activities:		
Net cash provided by operating activities	$ 80,325	$ 34,443
Net change in operating assets and liabilities	(3,072)	2,692
Interest expense	453	461
Current income tax provision (benefit)	188	(46)
Adjusted EBITDA	$ 77,894	$ 37,550

Our Adjusted EBITDA increased by approximately $40.3 million to approximately $77.9 million, or an increase of approximately 107%, for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. This increase in our Adjusted EBITDA is primarily attributable to the increase in our oil production and the associated increase in our oil and natural gas revenues for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011.

Credit Agreement

In December 2011, we entered into our second amended and restated senior secured revolving Credit Agreement for which Comerica Bank served as administrative agent. Among other things, this amendment increased the size of the facility and extended the term until December 2016. MRC Energy Company was the borrower under the amended Credit Agreement. Borrowings were secured by mortgages on substantially all of our oil and natural gas properties and by the equity interests of all of MRC Energy Company s wholly owned subsidiaries, which were also guarantors. In addition, all obligations under the Credit Agreement were guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with one of the lenders under the Credit Agreement (or an affiliate thereof) were also secured by the collateral and guaranteed by Matador Resources Company and the subsidiaries of MRC Energy Company.

The amount of the borrowings under the second amended and restated Credit Agreement were limited to the lesser of $400.0 million or the borrowing base, which was determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves, but also on external factors, such as the lenders lending policies and the lenders estimates of future oil and natural gas prices, over which we have no control. At December 31, 2011, the borrowing base was $125.0 million and we had $113.0 million in outstanding borrowings under the Credit Agreement. In January 2012, we borrowed an additional $10.0 million to finance a portion of our working capital requirements, bringing the then outstanding indebtedness under the Credit Agreement to $123.0 million. Following the completion of our Initial Public Offering, we used a portion of the net proceeds to repay the then outstanding $123.0 million under our Credit Agreement in February 2012, at which time the borrowing base was reduced to $100.0 million. On February 28, 2012, the borrowing base was increased to $125.0 million pursuant to a special borrowing base redetermination made at our request. This borrowing base increase was determined by our lenders based upon, among other items, the increase in our proved oil and natural gas reserves at December 31, 2011.

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On September 28, 2012, we entered into our third amended and restated senior secured revolving Credit Agreement. Among other things, this amendment increased the maximum facility amount from $400.0 million to $500.0 million, increased the borrowing base from $125.0 million to $200.0 million and named RBC as the administrative agent. In addition, the amendment provides for a conforming borrowing base of $165 million. The borrowing base will automatically be reduced to the conforming borrowing base on the earlier of (i) December 31, 2013 or (ii) the closing of a secondary public offering of equity interests that results in net cash proceeds to us in an amount greater than or equal to $25 million. The Credit Agreement matures December 29, 2016. MRC Energy Company is the borrower under the Credit Agreement. Borrowings are secured by mortgages on substantially all of our oil and natural gas properties and by the equity interests of all of MRC Energy Company s wholly owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador Resources Company, the parent corporation. Various commodity hedging agreements with two of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral and guaranteed by Matador Resources Company and the subsidiaries of MRC Energy Company.

Between March 1, 2012 and September 30, 2012, we borrowed $106.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At September 30, 2012, we had $106.0 million in borrowings outstanding under the Credit Agreement, approximately $1.1 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $92.9 million available for additional borrowings. At September 30, 2012, our outstanding borrowings bore interest at an effective interest rate of approximately 5.3% per annum as the borrowings were outstanding as a base rate advance. In early October, the borrowings were converted to a Eurodollar-based rate advance and bore interest at an effective rate of approximately 3.3%.

We expect to access future borrowings under our Credit Agreement to fund a portion of our 2012 capital expenditure requirements in excess of amounts available from our cash flows. We also intend to seek additional redeterminations of our borrowing base as a result of, among other items, any increases to our proved oil and natural gas reserves as a result of our ongoing drilling operations in the Eagle Ford shale. In October 2012 and November 2012, we borrowed an additional $14.0 million and $15.0 million, respectively, under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At November 14, 2012, we had $135.0 million in borrowings outstanding under the Credit Agreement, approximately $1.1 million in outstanding letters of credit issued pursuant to the Credit Agreement and approximately $63.9 million available for additional borrowings.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves. Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. In the event of a borrowing base increase, we are required to pay a fee to the lenders equal to a percentage of the amount of the increase, which will be determined based on market conditions at the time of the borrowing base increase. If the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day or (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.75% to 2.25% of such outstanding loan depending on the level of borrowings under the agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which RBC is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.75% to 3.25% of such outstanding loan depending on the level of borrowings under the agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee and any loan amortization costs in its interest rate calculations and related disclosures.

Key financial covenants under the third amended and restated Credit Agreement require the Company to maintain (1) a current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by consolidated total current liabilities, of 1.0 or greater measured at the end of each fiscal quarter beginning March 31, 2013 and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 or less.

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Subject to certain exceptions, our Credit Agreement contains various covenants that limit our, along with our subsidiaries , ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of our assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amount within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving us or our subsidiaries; and
- a change of control, as defined in the Credit Agreement.

At September 30, 2012, we believe that we were in compliance with the terms of our Credit Agreement.

Off-Balance Sheet Arrangements

At September 30, 2012, we did not have any off-balance sheet arrangements.

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Obligations and Commitments

We had the following material contractual obligations and commitments at September 30, 2012:

		Payments Due by Period			
(in thousands)	Total	Less Than 1 Year	1 -3 Years	3 -5 Years	More Than 5 Years
Contractual Obligations:					
Revolving credit borrowings, including letters of credit(1)	$ 107,100	$ 1,100	$	$ 106,000	$
Office lease	6,099	575	1,157	1,214	3,153
Non-operated drilling commitments(2)	3,630	3,630			
Drilling rig contracts(3)	3,691	3,691			
Asset retirement obligations	4,898	347	581	473	3,497
Gas processing agreement(4)	17,483	5,256	8,477	3,750	
Total contractual cash obligations	$ 142,901	$ 14,599	$ 10,215	$ 111,437	$ 6,650

(1) At September 30, 2012, we had $106.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $1.1 million in outstanding letters of credit issued pursuant to the Credit Agreement. The revolving borrowings are scheduled to mature in December 2016. These amounts do not include estimated interest on the obligations, because our revolving borrowings have short-term interest periods, and we are unable to determine what our borrowing costs may be in future periods.

(2) At September 30, 2012, we had outstanding commitments to participate in the drilling and completion of various non-operated wells, primarily in the Haynesville shale and the Eagle Ford shale. Our working interests in these wells are small, and most of these wells were in progress at September 30, 2012. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $3.6 million at September 30, 2012, which we expect to incur within the next 12 months.

(3) During the first quarter of 2012, we extended one of our drilling rig contracts in South Texas for an additional nine months. We terminated a second drilling contract with no termination penalty and entered into a new contract for a higher performance rig with the same drilling rig contractor for a period of one year. Drilling operations under these two contracts began in March 2012. Should we elect to terminate one or both contracts and if the drilling contractor were unable to secure work for one or both rigs or if the drilling contractor were unable to secure work for one or both rigs at the same daily rates being charged to us prior to the end of their respective contract terms, we would incur termination obligations. Our maximum outstanding aggregate termination obligations under these contracts were approximately $3.7 million at September 30, 2012.

(4) Effective September 1, 2012 we entered into a natural gas transportation and processing agreement that includes firm transportation and processing for most of our operated natural gas production in South Texas. The agreement expires on September 1, 2017 and includes fees that vary based on the price of natural gas, the quality of natural gas transported to the processing facility and the contract period. If we do not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, we will be required to pay a deficiency fee per MMBtu of natural gas deficiency. The total remaining maximum thermal quantity we are committed to transport and process under this agreement is 27.3 million MMBtu at September 30, 2012. The aggregate undiscounted minimum commitments under this agreement total approximately $17.5 million at September 30, 2012.

General Outlook and Trends

For the nine months ended September 30, 2012, oil prices ranged from a high of approximately $109.77 per Bbl in late February to a low of approximately $77.69 per Bbl in late June, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. Oil prices remained near or above $100 per Bbl for much of the first four months of 2012, but began declining in early May and throughout the remainder of the second quarter. During the third quarter, oil prices rebounded somewhat, ranging from a low of $83.75 per Bbl in early July, to a high of $99.00 per Bbl in mid-September. We realized a weighted average oil price of $102.86 per Bbl ($104.25 per Bbl including realized gains from oil derivatives) for our oil production for the nine months ended September 30, 2012 as compared to $92.71 per Bbl for the nine months ended September 30, 2011. At November 9, 2012, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $86.07 per Bbl as compared to $95.74 per Bbl at November 9, 2011.

For the nine months ended September 30, 2012, natural gas prices ranged from a low of approximately $1.91 per MMBtu in mid-April to a high of approximately $3.32 per MMBtu in late September, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Natural gas prices declined during most of the first three to four months of 2012, reaching their lowest levels in many years, before rallying to $3.32 per MMBtu in late September. We realized a weighted average natural gas price of $2.39 per Mcf ($3.47 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the nine months ended September 30, 2012 as compared to $3.80 per Mcf ($4.19 per Mcf including realized gains from natural gas derivatives) for the nine months ended September 30, 2011. At November 9, 2012, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $3.50 per MMBtu as compared to $3.65 per MMBtu at November 9, 2011.

The prices we receive for oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and these markets will likely continue to be volatile in the future. Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil and natural gas prices. Even so, decisions as to whether and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil and natural gas prices, and we may not always employ the optimal hedging strategy. Should oil or natural gas prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have an adverse effect on our business, financial condition, results of operations and reserves. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our wells in the Eagle Ford shale and the Haynesville shale experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil and natural gas price declines, however, we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves and cash flows.

We must focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, there have been no changes to our market risk since December 31, 2011 as set forth in the Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and natural gas liquids fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our future anticipated production.

We use costless (or zero-cost) collars to manage risks related to changes in oil and natural gas prices. A costless collar provides us with downside price protection through the purchase of a put option which is financed through the sale of a call option. We use swap agreements to mitigate risks related to changes in natural gas liquids (NGL) prices. A costless collar provides us with downside price protection through the purchase of a put option which is financed through the sale of a call option, both of which have a different fixed price component. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially costless to us. A swap also provides us with downside price protection and is similar to a costless collar except that the fixed price of both the put and call option are identical.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Comerica Bank and RBC (or affiliates thereof) are the counterparties for our commodity derivatives. We have considered the credit standings of the counterparties in determining the fair value of our derivative financial instruments.

We have entered into various costless collar transactions to mitigate our exposure to fluctuations in oil prices on a portion of our future anticipated oil production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to

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the calculation period s calendar month. When the settlement price is below the price floor established by these collars, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by these collars, we pay our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

We have also entered into various costless collar transactions to mitigate our exposure to fluctuations in natural gas prices on a portion of our future anticipated natural gas production, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period s calendar month for the last day of that contract period. When the settlement price is below the price floor established by these collars, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by these collars, we pay to our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

In August 2012, we entered into various swap contracts to mitigate our exposure to fluctuations in NGL prices on a portion of our future anticipated NGL production, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to us pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity as stated on the Mont Belvieu Spot Gas Liquids Prices:NON-TET prop on the pricing date. When the settlement price is below the fixed price established by these swaps, we receive from our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by these swaps, we pay to our counterparty an amount equal to the difference between the settlement and the fixed price multiplied by the contract NGL volume.

At September 30, 2012, we had multiple costless collar contracts open and in place to mitigate our exposure to oil and natural gas price volatility, each with a specified term (calculation period), notional quantity (volume hedged) and price floor and ceiling.

At September 30, 2012, we had multiple swap contracts open and in place to mitigate our exposure to natural gas liquids price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and fixed price.

The following table is a summary of the fair value of our open oil costless collar contracts at September 30, 2012.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (thousands)
Oil	10/01/2012 - 12/31/2012	20,000	90.00	104.20	$ 113
Oil	10/01/2012 - 12/31/2012	10,000	90.00	108.00	65
Oil	10/01/2012 - 12/31/2012	10,000	90.00	109.50	68
Oil	10/01/2012 - 12/31/2012	20,000	90.00	111.00	139
Oil	10/01/2012 - 12/31/2012	20,000	90.00	111.90	141
Oil	10/01/2012 - 12/31/2012	20,000	95.00	116.00	291
Oil	10/01/2012 - 03/31/2013	20,000	90.00	110.00	356
Oil	01/01/2013 - 12/31/2013	20,000	85.00	102.25	61
Oil	01/01/2013 - 12/31/2013	20,000	90.00	115.00	1,233
Oil	01/01/2013 - 12/31/2013	20,000	85.00	110.40	598
Oil	01/01/2013 - 12/31/2013	20,000	85.00	108.80	515
Oil	01/01/2013 - 06/30/2014	8,000	90.00	114.00	794
Oil	01/01/2013 - 06/30/2014	12,000	90.00	115.50	1,242
Total Oil					$ 5,616

All of our existing oil derivative contracts will expire at varying times during 2012, 2013 and 2014.

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The following is a summary of the fair value of our open natural gas costless collar contracts at September 30, 2012.

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	10/01/12 - 12/31/2012	300,000	4.50	5.60	$ 1,067
Natural Gas	10/01/12 - 12/31/2012	150,000	4.25	6.17	424
Natural Gas	10/01/12 - 12/31/2012	70,000	2.50	3.34	(36)
Natural Gas	10/01/12 - 07/31/2013	150,000	4.50	5.75	1,398
Natural Gas	10/01/12 - 07/31/2013	100,000	3.00	3.83	(381)
Total Natural Gas					$ 2,472

All of our existing natural gas derivative contracts will expire at varying times during 2012 and 2013.

The following is a summary of the fair value of our open NGL price swap contracts at September 30, 2012.

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Purity Ethane	10/01/2012 - 12/31/2012	55,700	0.333	$
Purity Ethane	10/01/2012 - 12/31/2012	55,700	0.337	
Propane	10/01/2012 - 12/31/2012	27,000	0.945	1
Propane	10/01/2012 - 12/31/2012	27,000	0.992	5
Normal Butane	10/01/2012 - 12/31/2012	7,500	1.465	
Normal Butane	10/01/2012 - 12/31/2012	7,500	1.580	3
Isobutane	10/01/2012 - 12/31/2012	4,000	1.535	(2)
Isobutane	10/01/2012 - 12/31/2012	4,000	1.675	(1)
Natural Gasoline	10/01/2012 - 12/31/2012	6,000	2.095	2
Natural Gasoline	10/01/2012 - 12/31/2012	6,000	2.150	3
Purity Ethane	01/01/2013 - 12/31/2013	110,000	0.335	(41)
Purity Ethane	01/01/2013 - 12/31/2013	110,000	0.355	(15)
Propane	01/01/2013 - 12/31/2013	53,000	0.953	7
Propane	01/01/2013 - 12/31/2013	53,000	1.001	38
Normal Butane	01/01/2013 - 12/31/2013	14,700	1.455	(3)
Normal Butane	01/01/2013 - 12/31/2013	14,700	1.560	16
Isobutane	01/01/2013 - 12/31/2013	7,000	1.515	(7)
Isobutane	01/01/2013 - 12/31/2013	7,000	1.625	3
Natural Gasoline	01/01/2013 - 12/31/2013	12,000	2.085	17
Natural Gasoline	01/01/2013 - 12/31/2013	12,000	2.102	19
Total open NGL swap contracts				$ 45

All of our existing NGL derivative contracts will expire at varying times during 2012 and 2013.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Prior to the completion of our Initial Public Offering, we maintained limited accounting personnel to perform our accounting processes and limited supervisory resources with which to address our internal control over financial reporting. In connection with our audit for the year ended December 31, 2011, our independent registered public accountants identified and communicated a material weakness related to accounting for stock compensation expense. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual and interim financial statements will not be prevented or detected and

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corrected on a timely basis. During the nine months ended September 30, 2012, we have placed additional controls around our accounting for stock based compensation procedures, including additional reviews of the computations by accounting personnel and external consultants. Based on the testing of these controls, we believe that this material weakness has been successfully remediated.

We became a public company on February 1, 2012 in connection with the completion of our Initial Public Offering. Prior to that date, we were a private company and were not required to file or submit reports under the Securities Exchange Act of 1934, as amended (the Exchange Act) and maintained disclosure controls and procedures in accordance with being a private company. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e)) under the Exchange Act was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon this evaluation, as of the end of the period covered by this report, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

We have in the past engaged and currently engage outside consultants to review significant or complex accounting issues and calculations. During the quarter ended September 30, 2012, there were no changes in our internal control that have materially affected or are reasonable likely to have a material effect on our internal control over financial reporting, except that we made several changes to our internal controls in preparation for management s assessment of internal controls over financial reporting that we will be required to file with our December 31, 2012 Form 10-K. These changes primarily consisted of ensuring that we maintained evidence of the execution of existing controls, as well as a formal documentation structure for all of our controls and processes. Where necessary, we also added additional reviews of certain documents, reconciliations and computations.

Part II Other Information

Item 1. Legal Proceedings

See Part I, Item 1 Financial Statements, Note 10 Commitments and Contingencies of this Quarterly Report on Form 10-Q which is incorporated by reference into this Part II, Item 1 Legal Proceedings.

Item 1A. Risk Factors

There have been no material changes to the risk factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibit Number	Description of Exhibits
10.1	Third Amended and Restated Credit Agreement, dated as of September 28, 2012, by and among MRC Energy Company, as Borrower, the Lending Entities from time to time parties thereto, as Lenders, and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 4, 2012).
10.2	Amendment, dated as of September 11, 2012, to Participation Agreement dated May 14, 2010, by and among MRC Rockies Company, Matador Resources Company (now known as MRC Energy Company), Matador Production Company, Roxanna Rocky Mountains, LLC, Roxanna Oil, Inc., Alliance Capital Real Estate, Inc. and Kimmeridge Energy Exploration Fund, LP (successor in interest to AllianceBerstein L.P.) (filed herewith).
10.3	Separation Agreement and Release by and between Matador Resources Company and Wade I. Massad, dated as of August 10, 2012 (incorporated by reference to Exhibit 10.9 to our Quarterly Report on Form 10-Q for the period ended June 30, 2012).
10.4	Consulting Agreement by and between Matador Resources Company and Wade I. Massad, dated as of August 10, 2012 (incorporated by reference to Exhibit 10.10 to our Quarterly Report on Form 10-Q for the period ended June 30, 2012).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101*	The following financial information from Matador Resources Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets - Unaudited, (ii) the Condensed Consolidated Statements of Operations - Unaudited, (iii) the Condensed Consolidated Statement of Changes in Shareholders Equity - Unaudited, (iv) the Condensed Consolidated Statements of Cash Flows - Unaudited and (v) the Notes to Condensed Consolidated Financial Statements (submitted electronically herewith).

* In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this quarterly report on Form 10-Q shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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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.

	MATADOR RESOURCES COMPANY
Date: November 14, 2012	By: /s/ Joseph Wm. Foran Joseph Wm. Foran Chairman, President and Chief Executive Officer
Date: November 14, 2012	By: /s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer