Matador Resources Co
Form 10-Q
August 09, 2013

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 June 30, 2013

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 (State or other jurisdiction of incorporation or organization)	27-4662601 (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 Dallas, Texas (Address of principal executive offices)	75240 (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	x
Non-accelerated filer	¨ (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 August 8, 2013, there were 55,844,162 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

Table of Contents

MATADOR RESOURCES COMPANY
FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2013
INDEX

Table of Contents

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)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash	$5,105	$ 2,095
Certificates of deposit	61	230
Accounts receivable		
Oil and natural gas revenues	25,193	24,422
Joint interest billings	1,792	4,118
Other	766	974
Derivative instruments	3,978	4,378
Lease and well equipment inventory	597	877
Prepaid expenses	1,318	1,103
Total current assets	38,810	38,197
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	912,618	763,527
Unproved and unevaluated	168,275	149,675
Other property and equipment	28,428	27,258
Less accumulated depletion, depreciation and amortization	(419,066)	(349,370)
Net property and equipment	690,255	591,090
Other assets		
Derivative instruments	3,459	771
Deferred income taxes	510	411
Other assets	1,677	1,560
Total other assets	5,646	2,742
Total assets	$734,711	$ 632,029
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$35,959	$ 28,120
Accrued liabilities	48,512	59,179
Royalties payable	6,335	6,541
Derivative instruments	257	670
Advances from joint interest owners	—	1,515
Income taxes payable	78	—
Deferred income taxes	510	411
Other current liabilities	87	56
Total current liabilities	91,738	96,492
Long-term liabilities		
Borrowings under Credit Agreement	245,000	150,000
Asset retirement obligations	5,881	5,109
Other long-term liabilities	2,067	1,324
Total long-term liabilities	252,948	156,433
Commitments and contingencies (Note 9)		

Shareholders' equity		
Common stock - $0.01 par value, 80,000,000 shares authorized; 57,139,755 and 56,778,718 shares issued; and 55,837,912 and 55,577,667 shares outstanding, respectively	571	568
Additional paid-in capital	405,614	404,311
Retained deficit	(5,395)	(15,010)
Treasury stock, at cost, 1,301,843 and 1,201,051 shares, respectively	(10,765)	(10,765)
Total shareholders' equity	390,025	379,104
Total liabilities and shareholders' equity	$734,711	$ 632,029

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

3

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - UNAUDITED
(In thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues				
Oil and natural gas revenues	$58,179	$36,078	$117,498	$65,242
Realized gain on derivatives	254	4,713	646	7,776
Unrealized gain on derivatives	7,526	15,114	2,701	11,844
Total revenues	65,959	55,905	120,845	84,862
Expenses				
Production taxes and marketing	4,451	2,619	8,548	4,783
Lease operating	10,140	6,375	21,040	11,020
Depletion, depreciation and amortization	20,234	19,913	48,466	31,119
Accretion of asset retirement obligations	80	58	161	111
Full-cost ceiling impairment	—	33,205	21,229	33,205
General and administrative	4,149	4,093	8,751	7,882
Total expenses	39,054	66,263	108,195	88,120
Operating income (loss)	26,905	(10,358)	12,650	(3,258)
Other income (expense)				
Net loss on asset sales and inventory impairment	(192)	(60)	(192)	(60)
Interest expense	(1,609)	(1)	(2,880)	(309)
Interest and other income	47	30	115	103
Total other expense	(1,754)	(31)	(2,957)	(266)
Income (loss) before income taxes	25,151	(10,389)	9,693	(3,524)
Income tax provision (benefit)				
Current	32	—	78	—
Deferred	—	(3,713)	—	(649)
Total income tax provision (benefit)	32	(3,713)	78	(649)
Net income (loss)	$25,119	$(6,676)	$9,615	$(2,875)
Earnings (loss) per common share				
Basic				
Class A	$0.45	$(0.12)	$0.17	$(0.06)
Class B	$—	$—	$—	$0.07
Diluted				
Class A	$0.45	$(0.12)	$0.17	$(0.06)
Class B	$—	$—	$—	$0.07
Weighted average common shares outstanding				
Basic				
Class A	55,839	55,271	55,729	52,434
Class B	—	—	—	210
Total	55,839	55,271	55,729	52,644
Diluted				
Class A	55,937	55,271	55,819	52,434
Class B	—	—	—	210
Total	55,937	55,271	55,819	52,644

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

4

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY - UNAUDITED
(In thousands)
For the Six Months Ended June 30, 2013

	Common Stock		Additional Paid-In Capital	Retained Deficit	Treasury Stock		Total
	Shares	Amount			Shares	Amount	
Balance at January 1, 2013	56,779	$568	$404,311	$(15,010)	1,201	$(10,765)	$379,104
Common stock issued to Board advisors	3	—	25	—	—	—	25
Stock options expense related to equity based awards	—	—	537	—	—	—	537
Liability based stock option awards settled	—	—	64	—	—	—	64
Changes in fair value for liability based awards for which grant date fair value is in excess of fair value	—	—	2	—	—	—	2
Restricted stock issued	358	3	(3)	—	—	—	—
Restricted stock forfeited	—	—	(22)	—	101	—	(22)
Restricted stock and restricted stock units expense	—	—	700	—	—	—	700
Current period net income	—	—	—	9,615	—	—	9,615
Balance at June 30, 2013	57,140	$571	$405,614	$(5,395)	1,302	$(10,765)	$390,025

The accompanying notes are an integral part of these financial statements.
5

Table of Contents

Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - UNAUDITED
(In thousands)

	Six Months Ended June 30, 2013	2012
Operating activities		
Net income (loss)	$9,615	$(2,875)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Unrealized gain on derivatives	(2,701)	(11,844)
Depletion, depreciation and amortization	48,466	31,119
Accretion of asset retirement obligations	161	111
Full-cost ceiling impairment	21,229	33,205
Stock-based compensation expense	1,524	(172)
Deferred income tax provision	—	(649)
Net loss on asset sales and inventory impairment	192	60
Changes in operating assets and liabilities		
Accounts receivable	1,763	(2,761)
Lease and well equipment inventory	280	(98)
Prepaid expenses	(215)	(385)
Other assets	(117)	59
Accounts payable, accrued liabilities and other current liabilities	4,615	1,687
Royalties payable	(206)	3,642
Advances from joint interest owners	(1,515)	—
Income taxes payable	78	—
Other long-term liabilities	743	427
Net cash provided by operating activities	83,912	51,526
Investing activities		
Oil and natural gas properties capital expenditures	(173,989)	(134,425)
Expenditures for other property and equipment	(2,081)	(3,521)
Purchases of certificates of deposit	(61)	(266)
Maturities of certificates of deposit	230	1,335
Net cash used in investing activities	(175,901)	(136,877)
Financing activities		
Repayments of borrowings under Credit Agreement	—	(123,000)
Borrowings under Credit Agreement	95,000	70,000
Proceeds from issuance of common stock	—	146,510
Swing sale profit contribution	—	24
Cost to issue equity	—	(11,599)
Proceeds from stock options exercised	—	2,660
Taxes paid related to net share settlement of stock-based compensation	(1)	—
Payment of dividends - Class B	—	(96)
Net cash provided by financing activities	94,999	84,499
Increase (decrease) in cash	3,010	(852)
Cash at beginning of period	2,095	10,284
Cash at end of period	$5,105	$9,432

Supplemental disclosures of cash flow information (Note 10)

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

Table of Contents

Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED

NOTE 1 - NATURE OF OPERATIONS

Matador Resources Company ("Matador" and, collectively, with its subsidiaries, the "Company") is 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. The Company's current operations are focused primarily on the oil and liquids rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas. The Company also operates in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, the Company has a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where the Company is testing the Meade Peak shale.

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, 2012 filed with the SEC (the "Annual Report"). 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 June 30, 2013, consolidated results of operations for the three and six months ended June 30, 2013 and 2012, consolidated changes in shareholders' equity for the six months ended June 30, 2013 and consolidated cash flows for the six months ended June 30, 2013 and 2012. 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, 2012 are derived from the audited consolidated financial statements in the Annual Report.

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, natural gas and natural gas liquids prices, global economic and financial market conditions, interest rates, access to sources of liquidity, estimates of reserves, drilling risks, geological risks, transportation restrictions, oil, natural gas and natural gas liquids supply and demand, market competition and interruptions of production.

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 period. 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

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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 $1.4 million and $1.1 million of its general and administrative costs for the six months ended June 30, 2013 and 2012, respectively. The Company capitalized approximately $0.8 million and $0.6 million of its interest expense for the six months ended June 30, 2013 and 2012, 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 July 2012 through June 2013, these average oil and natural gas prices were $88.13 per Bbl and $3.444 per MMBtu (million British thermal units), respectively. For the period July 2011 through June 2012, these average oil and natural gas prices were $92.17 per Bbl and $3.146 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 June 30, 2013 and 2012, 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.

Using the average commodity prices, as adjusted, to determine the Company's estimated proved oil and natural gas reserves at June 30, 2013, the Company's net capitalized costs less related deferred income taxes did not exceed the full-cost ceiling. As a result, the Company recorded no impairment to its net capitalized costs for the three months ended June 30, 2013. At March 31, 2013, the Company's net capitalized costs less related deferred taxes exceeded the full-cost ceiling by $13.7 million. The Company recorded an impairment charge of $21.2 million to its net capitalized costs and a deferred income tax credit of $7.5 million for the three months ended March 31, 2013. These charges are reflected in the Company's unaudited condensed consolidated statement of operations for the six months ended June 30, 2013. At June 30, 2013, the Company retained a full valuation allowance against its deferred tax assets, and as a result, the Company recorded no deferred income tax provision to its unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2013. 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. Changes in oil and natural gas production rates, reserves

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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 consolidated balance sheet, as well as the corresponding consolidated shareholders' equity, but it has no impact on the Company's consolidated 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 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 six months ended June 30, 2013 and 2012 totaled zero and $27,643, respectively. 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 June 30, 2013, the Company had not paid any dividends to holders of the Class A shares. Concurrent with the completion of the Company's 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.

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 six months ended June 30, 2013 and 2012 (in thousands, except per share data).

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss) — numerator				
Net income (loss)	$25,119	$(6,676)	$9,615	$(2,875)
Less dividends to Class B shareholders — distributed earnings	—	—	—	(28)
Undistributed earnings (loss)	$25,119	$(6,676)	$9,615	$(2,903)
Weighted average common shares outstanding — denominator				
Basic				
Class A	55,839	55,271	55,729	52,434
Class B	—	—	—	210
Total	55,839	55,271	55,729	52,644
Diluted				
Class A				
Weighted average common shares outstanding for basic earnings (loss) per share	55,839	55,271	55,729	52,434
Dilutive effect of options and restricted stock units	98	—	90	—
Class A weighted average common shares outstanding - diluted	55,937	55,271	55,819	52,434
Class B				
Weighted average common shares outstanding – no associated dilutive shares	—	—	—	210
Total diluted weighted average common shares outstanding	55,937	55,271	55,819	52,644

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Earnings (loss) per common share				
Basic				
Class A				
Distributed earnings	$—	$—	$—	$—
Undistributed earnings (loss)	$0.45	$(0.12)	$0.17	$(0.06)
Total	$0.45	$(0.12)	$0.17	$(0.06)
Class B				
Distributed earnings	$—	$—	$—	$0.13
Undistributed earnings	$—	$—	$—	$(0.06)
Total	$—	$—	$—	$0.07
Diluted				
Class A				
Distributed earnings	$—	$—	$—	$—
Undistributed earnings (loss)	$0.45	$(0.12)	$0.17	$(0.06)
Total	$0.45	$(0.12)	$0.17	$(0.06)
Class B				
Distributed earnings	$—	$—	$—	$0.13

Undistributed earnings	$—	$—	$—	$(0.06)
Total	$—	$—	$—	$0.07

A total of 1,293,568 options to purchase shares of the Company's Class A common stock and 139,963 restricted stock units were excluded from the calculations above for the three and six months ended June 30, 2012, because their effects were anti-dilutive. Additionally, 231,683 restricted shares, which are participating securities, were excluded from the calculations above for the three and six months ended June 30, 2012, as these security holders do not have the obligation to share in the losses of the Company.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

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.

Recent Accounting Pronouncements

Balance Sheet. In January 2013, the FASB issued Accounting Standards Update, or ASU, 2013-01, Balance Sheet. The ASU clarifies the scope of ASU 2011-11 to limit the application of ASU 2011-11 to derivatives accounted for in accordance with Accounting Standards Codification, or ASC, 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The Company adopted ASU 2013-01 effective January 1, 2013, together with the adoption of ASU 2011-11. The adoption of ASUs 2013-01 and 2011-11 did not have a material effect on the Company’s consolidated financial statements but did require certain additional disclosures (see Note 7).

Balance Sheet. In December 2011, the FASB issued ASU 2011-11, Balance Sheet. The requirements amend the disclosure requirements related to offsetting in 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 Company adopted ASU 2011-11 effective January 1, 2013, together with the adoption of ASU 2013-01. The adoption of ASUs 2011-11 and 2013-01 did not have a material effect on the Company’s consolidated financial statements but did require certain additional disclosures (see Note 7).

NOTE 3 - ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company’s asset retirement obligations for the six months ended June 30, 2013 (in thousands).

Beginning asset retirement obligations	$5,769
Liabilities incurred during period	214
Liabilities settled during period	(1)
Revisions in estimated cash flows	542
Accretion expense	161
Ending asset retirement obligations	6,685
Less: current asset retirement obligations[1]	(804)
Long-term asset retirement obligations	$5,881

[1] Included in accrued liabilities in the Company’s unaudited condensed consolidated balance sheet at June 30, 2013.

NOTE 4 - REVOLVING CREDIT AGREEMENT

On September 28, 2012, the Company amended and restated its revolving credit agreement. This third amended and restated credit agreement (the “Credit Agreement”) increased the maximum facility amount from $400.0 million to $500.0 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 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 certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by the eligible 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 at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2013, the lenders completed their review of the Company’s proved oil and natural gas reserves at December 31, 2012, and on March 11, 2013, the borrowing base was increased from $215.0 million to $255.0 million. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $220.0 million. At that time, the Company also amended the Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and IberiaBank in the Company’s lending group, which also includes RBC as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia and SunTrust Bank. This March 11, 2013 redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, the Company requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to $280.0 million.

On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million and the conforming borrowing base was increased to $275.0 million. At that time, the Company amended the Credit Agreement to provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by the Company of senior unsecured notes in an amount greater than or equal to $10.0 million. This August redetermination constituted the regularly scheduled November 1 redetermination. The Company may request one additional unscheduled redetermination of its borrowing base prior to the next scheduled redetermination.

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 is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, 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.

NOTE 4 - REVOLVING CREDIT AGREEMENT - Continued

In connection with the March and June 2013 borrowing base redeterminations, the Company incurred $0.1 million of additional deferred loan costs. These costs were included with the remaining unamortized balance of the deferred loan costs incurred previously. As a result, total deferred loan costs were $1.7 million at June 30, 2013, and these costs are being amortized over the term of the agreement, which approximates the amortization of these costs using the effective interest method. At June 30, 2013, the Company had $245.0 million in borrowings outstanding under the Credit Agreement and approximately $1.2 million in outstanding letters of credit issued pursuant to the Credit Agreement. At June 30, 2013, the outstanding borrowings bore interest at an effective interest rate of approximately 3.6% per annum. Subsequent to June 30, 2013, the Company borrowed an additional $15.0 million to fund a portion of its working capital requirements and the acquisition of additional leasehold interests in Southeast New Mexico. At August 8, 2013, the Company had $260.0 million in borrowings outstanding under the Credit Agreement and approximately $1.2 million in outstanding letters of credit issued pursuant to the Credit Agreement.

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 3.00% of such outstanding loan depending on the level of borrowings under the 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 4.00% 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, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees as interest expense and in its interest rate calculations and related disclosures. 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 June 30, 2014 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 its 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 amounts 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 June 30, 2013, the Company believes that it was in compliance with the terms of its Credit Agreement.

13

NOTE 5 - INCOME TAXES

Based upon its projections for the remainder of 2013, the Company anticipates incurring a small alternative minimum tax (“AMT”) liability for the year ending December 31, 2013, the proportionate shares of which are recorded as the current income tax provision for the three and six months ended June 30, 2013. The Company established a valuation allowance at September 30, 2012 and retained a full valuation allowance of approximately $6.7 million at June 30, 2013 due to uncertainties regarding the future realization of its net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the three and six months ended June 30, 2013, other than the AMT liability noted above. The Company had a net loss for the three and six months ended June 30, 2012.

NOTE 6 - STOCK-BASED COMPENSATION

In March 2013, the Company granted awards of options to purchase 507,500 and 284,292 shares of the Company’s common stock at exercise prices of $8.21 per share and $8.18 per share, respectively, to certain of its employees. The fair value of these awards was approximately $2.8 million. The Company also granted awards of 324,771 shares of restricted stock to certain of its employees in March 2013. The fair value of these restricted stock awards was approximately $2.4 million. All of these awards vest over a term of three or four years.

In February 2013, options to purchase 408,000 shares of the Company’s common stock at $10.00 per share expired unexercised or were forfeited.

NOTE 7 - 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 in its consolidated balance sheet as either assets or liabilities 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, The Bank of Nova Scotia and RBC (or affiliates thereof) were the counterparties for our commodity derivatives at June 30, 2013. The Company has considered the credit standings of the counterparties in determining the fair value of its derivative financial instruments.

The Company has entered into various costless collar contracts to mitigate its exposure to fluctuations in oil prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss 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 one or more of these collars, the Company receives from the 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 one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

The Company has also entered into various swap contracts to mitigate its exposure to fluctuations in oil prices, each with an established fixed price. For each calculation period, the specified price for determining the realized gain or loss 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 fixed price established by one or more of these swaps, the Company receives from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume. When the settlement price is above the fixed price established by one or more of these swaps, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume.

The Company has entered into various costless collar transactions for natural gas, 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 one or more of these collars, the Company receives from the counterparty an amount equal

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

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 one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

The Company has entered into various swap contracts to mitigate its exposure to fluctuations in natural gas liquids ("NGL") prices, 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, except for purity ethane, as stated on the "Mont Belvieu Spot Gas Liquids Prices: NON-TET prop" on the pricing date. The settlement price for purity ethane is the arithmetic average of any current month for delivery on the nearby month futures contracts as stated on the "Mont Belvieu Spot Gas Liquids Prices" on the pricing date. When the settlement price is below the fixed price established by one or more of these swaps, the Company receives from the 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 one or more of these swaps, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At June 30, 2013, the Company had various 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 2013, 2014 and 2015.

At June 30, 2013, the Company had various swap contracts open and in place to mitigate its exposure to oil and 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 2013 and 2014.

Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 7 - 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 oil and natural gas liquids at June 30, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	07/01/2013 - 12/31/2013	20,000	85.00	102.25	$(9)
Oil	07/01/2013 - 12/31/2013	20,000	85.00	108.80	84
Oil	07/01/2013 - 12/31/2013	20,000	85.00	110.40	94
Oil	07/01/2013 - 12/31/2013	20,000	90.00	102.80	126
Oil	07/01/2013 - 12/31/2013	20,000	90.00	115.00	224
Oil	07/01/2013 - 06/30/2014	8,000	90.00	114.00	336
Oil	07/01/2013 - 06/30/2014	12,000	90.00	115.50	513
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	248
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	546
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	349
Oil	01/01/2014 - 12/31/2014	20,000	88.00	95.60	444
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	763
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	642
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	637
Total open oil costless collar contracts					4,997

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	07/01/2013 - 07/31/2013	150,000	4.50	5.75	119
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.00	3.83	(57)
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.00	4.95	9
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.00	4.96	10
Natural Gas	07/01/2013 - 12/31/2013	150,000	3.00	4.24	(25)
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.25	4.41	14
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.25	4.44	16
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.50	4.37	55
Natural Gas	08/01/2013 - 12/31/2013	80,000	3.75	4.57	104
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(26)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	45
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	45
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	64
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	68
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	98
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	200
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	207
Total open natural gas costless collar contracts					946

Commodity	Calculation Period	Notional Quantity	Fixed Price	Fair Value of

		(Bbl/month)	($/Bbl)	Liability (thousands)
Oil	07/01/2013 - 12/31/2013	10,000	90.20	(295)
Oil	07/01/2013 - 12/31/2013	10,000	90.65	(269)
Total open oil swap contracts				(564)

16

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (thousands)
Purity Ethane	07/01/2013 - 12/31/2013	110,000	0.335	57
Purity Ethane	07/01/2013 - 12/31/2013	110,000	0.355	71
Propane	07/01/2013 - 12/31/2013	53,000	0.953	30
Propane	07/01/2013 - 12/31/2013	106,000	0.960	65
Propane	07/01/2013 - 12/31/2013	53,000	1.001	45
Propane	01/01/2014 - 12/31/2014	116,000	0.950	141
Normal Butane	07/01/2013 - 12/31/2013	14,700	1.455	22
Normal Butane	07/01/2013 - 12/31/2013	14,700	1.560	32
Normal Butane	07/01/2013 - 12/31/2013	21,000	1.575	47
Normal Butane	07/01/2013 - 12/31/2013	117,000	1.575	268
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	75
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	211
Isobutane	07/01/2013 - 12/31/2013	7,000	1.515	11
Isobutane	07/01/2013 - 12/31/2013	7,000	1.625	16
Isobutane	07/01/2013 - 12/31/2013	43,500	1.675	110
Isobutane	07/01/2013 - 12/31/2013	23,000	1.675	62
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	114
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	184
Natural Gasoline	07/01/2013 - 12/31/2013	12,000	2.025	4
Natural Gasoline	07/01/2013 - 12/31/2013	12,000	2.085	8
Natural Gasoline	07/01/2013 - 12/31/2013	12,000	2.102	9
Natural Gasoline	07/01/2013 - 12/31/2013	36,000	2.105	29
Natural Gasoline	07/01/2013 - 12/31/2013	90,500	2.148	98
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	32
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	60
Total open NGL swap contracts				1,801
Total open derivative financial instruments				$7,180

These derivative financial instruments are subject to master netting arrangements within specific commodity types, i.e., oil, natural gas and natural gas liquids, by counterparty. Derivative financial instruments with Counterparty A are not subject to master netting across commodity types, while derivative financial instruments with Counterparties B and C allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheet.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of June 30, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the consolidated balance sheet	Net amounts of assets presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$3,682	$(1,823)	$1,859	$—
Other assets	2,858	(1,467)	1,391	—
Counterparty B				
Current assets	2,239	(1,264)	975	257
Other assets	2,859	(1,510)	1,349	—
Counterparty C				
Current assets	2,231	(1,087)	1,144	—
Other assets	1,699	(980)	719	—
Total	$15,568	$(8,131)	$7,437	$257

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of June 30, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the consolidated balance sheet	Net amounts of liabilities presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$1,823	$(1,823)	$—	$—
Long-term liabilities	1,467	(1,467)	—	—
Counterparty B				
Current liabilities	1,521	(1,264)	257	257
Long-term liabilities	1,510	(1,510)	—	—
Counterparty C				
Current liabilities	1,087	(1,087)	—	—
Long-term liabilities	980	(980)	—	—
Total	$8,388	$(8,131)	$257	$257

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 7 - DERIVATIVE FINANCIAL INSTRUMENTS - Continued

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of December 31, 2012 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of assets presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$6,445	$(2,373)	$4,072	$—
Other assets	1,096	(370)	726	—
Counterparty B				
Current assets	530	(224)	306	82
Other assets	384	(339)	45	—
Total	$8,455	$(3,306)	$5,149	$82

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its unaudited condensed consolidated balance sheet as of December 31, 2012 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the condensed consolidated balance sheet	Net amounts of liabilities presented in the condensed consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$2,373	$(2,373)	$—	$—
Long-term liabilities	370	(370)	—	—
Counterparty B				
Current liabilities	894	(224)	670	82
Long-term liabilities	339	(339)	—	—
Total	$3,976	$(3,306)	$670	$82

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 7 - 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).

		Three Months Ended June 30,		Six Months Ended June 30,	
Type of Instrument	Location in Condensed Consolidated Statement of Operations	2013	2012	2013	2012
Derivative Instrument					
Oil	Revenues: Realized (loss) gain on derivatives	$(228)	$719	$(465)	$719
Natural Gas	Revenues: Realized gain on derivatives	105	3,994	629	7,057
NGL's	Revenues: Realized gain on derivatives	377	—	482	—
Realized gain on derivatives		254	4,713	646	7,776
Oil	Revenues: Unrealized gain on derivatives	4,042	20,483	1,314	15,223
Natural Gas	Revenues: Unrealized gain (loss) on derivatives	2,323	(5,369)	(189)	(3,379)
NGL's	Revenues: Unrealized gain on derivatives	1,161	—	1,576	—
Unrealized gain on derivatives		7,526	15,114	2,701	11,844
Total		$7,780	$19,827	$3,347	$19,620

NOTE 8 - 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 June 30, 2013 and December 31, 2012, the carrying values reported on the unaudited condensed consolidated balance sheets for cash, accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities and are classified at Level 1.

At June 30, 2013 and December 31, 2012, 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 June 30, 2013 and December 31, 2012 (in thousands).

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 8 - FAIR VALUE MEASUREMENTS - Continued

	Fair Value Measurements at June 30, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$—	$61	$—	$61
Oil, natural gas and NGL derivatives	—	7,437	—	7,437
Oil, natural gas and NGL derivatives	—	(257)	—	(257)
Total	$—	$7,241	$—	$7,241

	Fair Value Measurements at December 31, 2012 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$—	$230	$—	$230
Oil, natural gas and NGL derivatives	—	5,149	—	5,149
Oil, natural gas and NGL derivatives	—	(670)	—	(670)
Total	$—	$4,709	$—	$4,709

Additional disclosures related to derivative financial instruments are provided in Note 7. 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.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 8 - FAIR VALUE MEASUREMENTS - Continued

The Company accounts for additions to asset retirement obligations and lease and well equipment inventory when adjusted for impairment 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 June 30, 2013 and December 31, 2012 (in thousands).

	Fair Value Measurements at June 30, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(756)	$(756)
Lease and well equipment inventory	—	—	21	21
Total	$—	$—	$(735)	$(735)

	Fair Value Measurements at December 31, 2012 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$—	$—	$(1,243)	$(1,243)
Lease and well equipment inventory	—	—	34	34
Total	$—	$—	$(1,209)	$(1,209)

For purposes of fair value measurement, the Company determined that additions and revisions to asset retirement obligations should be classified at Level 3. The Company recorded additions to asset retirement obligations and revisions of estimated cash flows of approximately $0.8 million for the six months ended June 30, 2013 and $1.2 million for the year ended December 31, 2012.

For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified at Level 3 when adjusted for impairment. In 2012, the Company recorded an impairment to some of its equipment held in inventory consisting primarily of drilling rig parts of $425,000 and pipe and other equipment of $60,464. During the three months ended June 30, 2013, the Company recorded an impairment to some of its pipe held in inventory of $192,410. 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 9 - COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas. In April 2013, the Company entered into the fifth amendment to its office lease agreement. This amendment increased the square footage of its corporate headquarters to 40,071 square feet effective July 1, 2013. The lease expires on June 30, 2022.

Natural Gas and NGL Processing and Transportation Commitments

Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its firm natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this agreement, 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 natural 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

NOTE 9 - COMMITMENTS AND CONTINGENCIES - Continued

commitments under this agreement. The Company's remaining aggregate undiscounted minimum commitments under this agreement are $13.7 million at June 30, 2013. The Company paid approximately $1.0 million and $1.8 million in processing and transportation fees under this agreement during the three and six months ended June 30, 2013.

Other Commitments

From time to time, the Company enters into contracts with third parties for drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided, which are typically for one year or less. Should the Company elect to terminate a contract and if the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms, the Company would incur termination obligations. The Company's maximum outstanding aggregate termination obligations under its drilling rig contracts were approximately $2.0 million at June 30, 2013.

In July 2013, the Company entered into a contract for a drilling rig to continue to explore and develop its acreage in the Eagle Ford shale in South Texas. Drilling operations under this contract are scheduled to commence in late August 2013 and the term of the contract is 180 days from the commencement date. Should the Company elect to terminate this contract and if the drilling contractor were unable to secure work for the rig or if the drilling contractor were unable to secure work for the rig at the same daily rate being charged to the Company, the Company would incur termination obligations. The Company's maximum termination obligation under this contract was approximately $2.7 million at August 8, 2013.

At June 30, 2013, the Company had agreed to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed, the Company will have minimum outstanding aggregate commitments for its participation in these wells of approximately $6.6 million at June 30, 2013, which it expects to incur within the next few months.

Legal Proceedings

Cynthia Fry Peironnet, et al. v. MRC Energy Company f/k/a 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. The Trial Court rendered multiple rulings in 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 the Company on June 6, 2011. On August 1, 2012, the Louisiana Second Circuit Court 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 filed an appeal with the Louisiana Supreme Court. The Louisiana Supreme Court granted the requests to hear an appeal of the Court of Appeal's decision, and in June 2013, the Louisiana Supreme Court reversed the decision of the Court of Appeal and reinstated the Trial Court judgment in its entirety. The plaintiffs have filed an application for rehearing with the Louisiana Supreme Court.

The Company believes that the facts of the case and the applicable law do not support the plaintiffs' application for rehearing. In the opinion of management, it is remote that this litigation will have a material adverse impact on the Company's financial position, results of operations or cash flows.

NOTE 9 - COMMITMENTS AND CONTINGENCIES - Continued

MRC Energy Company f/k/a Matador Resources Company, v. Orca ICI Development, J.V. The Company and Orca, a non-operator working interest owner, had various disputes regarding certain of the Company's Eagle Ford shale wells and properties. Among other things, issues arose with respect to the rights and obligations of the Company and Orca under various agreements between the parties, and Orca sought the Company's consent to Orca's proposed assignment of its 50 percent working interest in the Cowey #3H and #4H wells to a non-industry person, despite the presence of a uniform maintenance of interest provision. On April 2, 2013, Orca brought suit against the Company in the 57th Judicial District Court of Bexar County, Texas and sought injunctive relief. The court denied Orca's demand for injunctive relief, and on April 5, 2013, the Company moved to enforce arbitration provisions in the agreements between the parties. On April 22, 2013, the Company initiated an arbitration against Orca, seeking, among other things, a declaration that the Company could withhold its consent to Orca's putative assignment of these interests. Pursuant to agreements reached between the parties in May and June 2013, Orca and the Company agreed to resolve all outstanding issues between the parties regarding the respective rights and obligations of the parties under the agreements between them. In addition, the Company agreed to bear 100% of the costs to drill, complete and equip the Cowey #3H and #4H wells. Until such time as the Company has recovered 100% of the costs to drill, complete and equip the wells, all revenues generated by production from these two wells will be attributable to the Company. Following the Company's recovery of these amounts, Orca would participate in the wells for a 25% working interest. The Company has returned $8.7 million submitted by Orca's putative assignee. The agreements also included a mutual release of claims between the Company and Orca and provided for the dismissal of the Bexar County litigation. Orca filed a notice of non-suit on August 7, 2013.

The Company is a defendant in several other lawsuits encountered in the ordinary course of its business. In the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial position, results of operations or cash flows.

NOTE 10 - SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at June 30, 2013 and December 31, 2012 (in thousands).

	June 30, 2013	December 31, 2012
Accrued evaluated and unproved and unevaluated property costs	$38,297	$ 45,592
Accrued support equipment and facilities costs	467	1,382
Accrued stock-based compensation	—	65
Accrued lease operating expenses	5,823	5,218
Accrued interest on borrowings under Credit Agreement	186	255
Accrued asset retirement obligations	804	660
Accrued partners' share of joint interest charges	131	3,597
Other	2,804	2,410
Total accrued liabilities	$48,512	$ 59,179

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - UNAUDITED - CONTINUED

NOTE 10 - SUPPLEMENTAL DISCLOSURES - Continued

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2013 and 2012 (in thousands).

	Six Months Ended June 30,	
	2013	2012
Cash paid for interest expense, net of amounts capitalized	$1,817	$226
Asset retirement obligations related to mineral properties	751	293
Asset retirement obligations related to support equipment and facilities	4	33
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	(6,859)	8,995
(Decrease) increase in liabilities for support equipment and facilities	(914)	(215)
(Decrease) increase in liabilities for accrued cost to issue equity	—	(331)
Issuance of restricted stock units for Board and advisor services	87	10
Issuance of common stock for advisor services	17	61
Stock-based compensation expense recognized as liability	284	(491)
Transfer of inventory from oil and natural gas properties	191	—

NOTE 11 - SUBSIDIARY GUARANTORS
Matador filed a registration statement on Form S-3 with the SEC, which became effective May 9, 2013, and registered, among other securities, debt securities. The subsidiaries of Matador (the “Subsidiaries”) are co-registrants with Matador, and the registration statement registers guarantees of debt securities by the Subsidiaries. As of June 30, 2013, the Subsidiaries are 100 percent owned by Matador and any guarantees by the Subsidiaries will be full and unconditional (except for customary release provisions). Matador has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to Matador. In the event that more than one of the Subsidiaries provide guarantees of any debt securities issued by Matador, such guarantees will constitute joint and several obligations.

Table of Contents

NOTE 12 - SUBSEQUENT EVENTS

In July and August 2013, the Company acquired approximately 6,600 gross and 3,600 net acres prospective for the Wolfcamp and Bone Spring formations in Southeast New Mexico and West Texas. The Company paid approximately $7.6 million to acquire this acreage.

Table of Contents

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

The following discussion and analysis of our financial condition and results of operations 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, 2012 filed with the SEC (the "Annual Report"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Annual Report. 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 the "Risk Factors" section of the Annual Report and 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 (the "Quarterly Report"), references to "we," "our" or "the Company" refer to Matador Resources Company and its subsidiaries as a whole and references to "Matador" refer solely 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 the Annual Report.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report 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, "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 success of our drilling program, 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 Quarterly 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;
- 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;

Table of Contents

- 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;
- 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 the Annual Report.

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, including the securities laws of the United States and the rules and regulations of the SEC.

Overview

Matador Resources Company is 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 focused primarily on the oil and liquids rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. The Company also has a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where we are testing the Meade Peak shale.

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Commodity price volatility, in particular, is a significant risk factor for us. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, oil and natural gas price differentials and other factors. Prices for oil, natural gas and natural gas liquids will affect the cash flows available to us for capital expenditures and our ability to borrow and raise additional capital. Declines in oil, natural gas or natural gas liquids prices would not only reduce our revenues, but could also reduce the amount of oil, natural gas or natural gas liquids that we can produce economically, and as a result, could have an adverse effect on our financial condition, results of operations, cash flows, reserves and borrowing base under our Credit Agreement.

During the first six months of 2013, our operations were focused primarily on the exploration and development of our Eagle Ford shale properties in South Texas. During the six months ended June 30, 2013, we completed and began producing oil and natural gas from 11 gross (11.0 net) operated and 2 gross (0.8 net) non-operated Eagle Ford shale wells. We also

Table of Contents

participated in 5 gross (0.4 net) non-operated Haynesville shale wells in Northwest Louisiana and one non-operated test of the Buda formation in South Texas (approximately 21% working interest).

We had two contracted drilling rigs operating continuously during the six months ended June 30, 2013. During the first quarter of 2013, both of these rigs were operating in South Texas, and all of our operated drilling and completion activities were focused on the Eagle Ford shale. In late April 2013, we moved one of these contracted drilling rigs to Southeast New Mexico to begin a three-well exploration program testing portions of our leasehold position in the Delaware Basin in Southeast New Mexico and West Texas. As these are the first wells we are drilling in this area, we expect to collect additional well log, core and other petrophysical data on these initial test wells. As a result, these wells are expected to take longer to drill and complete and will cost more than we anticipate for subsequent wells once we begin development drilling in this area. At August 8, 2013, we were testing potential completion intervals in our first well (Ranger 12 State #1) and were drilling our second well (Ranger 33 State Com #1H) in Lea County, New Mexico. We had two contracted drilling rigs operating - one in Gonzales County, Texas and the other in Lea County, New Mexico. We expect to return to a two-rig program in the Eagle Ford shale in South Texas in late August 2013 and plan to operate three rigs for a short period of time during the third quarter while we complete drilling operations on our first well in Loving County, Texas.

During the three months ended June 30, 2013 specifically, we completed and began producing oil and natural gas from 7 gross (7.0 net) operated and 2 gross (0.8 net) non-operated Eagle Ford shale wells. We completed three operated Eagle Ford wells on our Cowey lease in DeWitt County, Texas and four wells on our Martin Ranch lease in northeast LaSalle County, Texas. We completed and began producing oil and natural gas from two non-operated Eagle Ford wells on our Troutt leasehold in central LaSalle County. We also participated in 3 gross (0.4 net) non-operated Haynesville shale wells in Northwest Louisiana. The two non-operated Troutt wells began producing in early May 2013, the three wells on the Cowey lease began producing in mid-May, and the four Martin Ranch wells began producing in early June 2013. As a result, these wells did not contribute fully to our second quarter production volumes. Furthermore, these seven operated wells were the first Eagle Ford wells we had placed on production since early February 2013. In addition, we shut in up to 20% of our total production at various times during the second quarter of 2013, averaging about 10% to 12% of total production capacity shut in during the quarter, as we continued our practice of shutting in offsetting producing wells while we completed and conducted fracturing operations on these new wells.

Our average daily oil equivalent production for the three months ended June 30, 2013 was 10,582 BOE per day, including 4,916 Bbl of oil per day and 34.0 MMcf of natural gas per day, an increase of 21%, as compared to 8,738 BOE per day, including 3,130 Bbl of oil per day and 33.6 MMcf of natural gas per day for the three months ended June 30, 2012. As noted above, due to our pad drilling operations and shutting in various producing wells, we had an average of approximately 10% to 12% of our total production capacity shut-in during the second quarter of 2013. As a result, our average daily oil equivalent production of 10,582 BOE per day decreased about 3% sequentially from an average daily oil equivalent production of approximately 10,900 BOE per day during the first quarter of 2013. Our average daily oil production of 4,916 Bbl of oil per day for the three months ended June 30, 2013 was an increase of 57% from an average daily oil production of 3,130 Bbl of oil per day for the three months ended June 30, 2012. This year-over-year increase in our average daily oil equivalent production and, in particular, our average daily oil production is directly attributable to our ongoing drilling operations in the Eagle Ford shale. Our average daily oil equivalent production for the six months ended June 30, 2013 was approximately 10,739 BOE per day, including 5,015 Bbl of oil per day and 34.3 MMcf of natural gas per day, an increase of 28%, as compared to 8,380 BOE per day, including 2,670 Bbl per day of oil and 34.3 MMcf of natural gas per day for the six months ended June 30, 2012. Our average daily oil production of 5,015 Bbl of oil per day for the six months ended June 30, 2013 was an increase of 88%, as compared to an average daily oil production of 2,670 Bbl per day during the first six months of 2012. Oil production comprised 46% and 47% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the three and six months ended June 30, 2013, respectively, as compared to approximately 36% and

32%, respectively, of our total production for the three and six months ended June 30, 2012. A step change in our production occurred during the second quarter of 2013. Our production averaged 4,825 Bbl of oil per day and 33.8 MMcf of natural gas per day in the first five months of 2013. Since June 1, 2013, however, most of the shut-in wells have been returned to production along with the recently competed wells, and, as a result, our exit production rate at June 30, 2013 was approximately 6,000 Bbl of oil per day. We averaged 6,200 Bbl of oil per day and 38.4 MMcf of natural gas per day during June and July 2013.

For the three months ended June 30, 2013, our oil and natural gas revenues were $58.2 million, an increase of 61% from oil and natural gas revenues of $36.1 million for the three months ended June 30, 2012. Our oil revenues increased 52% to $44.6 million during the second quarter of 2013, as compared to oil revenues of $29.4 million during the second quarter of 2012. This increase reflects our increase in oil production of 57% during the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. Our natural gas revenues more than doubled to $13.5 million for the three months ended June 30, 2013, as compared to natural gas revenues of $6.7 million during the three months ended June 30, 2012. This increase

Table of Contents

in natural gas revenues was primarily due to a doubling in the natural gas prices we realized between these periods to $4.38 per Mcf during the second quarter of 2013 from $2.17 per Mcf during the second quarter of 2012. For the six months ended June 30, 2013, our oil and natural gas revenues were $117.5 million, an increase of 80% from oil and natural gas revenues of $65.2 million for the six months ended June 30, 2012. Our oil revenues increased 83% to $93.3 million during the first six months of 2013, as compared to oil revenues of $51.0 million for the first six months of 2012. Our natural gas revenues increased 70% to $24.2 million for the six months ended June 30, 2013, as compared to natural gas revenues of $14.3 million for the six months ended June 30, 2012. Our oil and natural gas revenues of $117.5 million for the six months ended June 30, 2013 increased 29% compared to $90.8 million for the six months ended December 31, 2012. For the three months ended June 30, 2013, our Adjusted EBITDA was $40.8 million, an increase of 46% from an Adjusted EBITDA of $27.9 million reported for the three months ended June 30, 2012, and slightly higher than an Adjusted EBITDA of $40.7 million reported for the first quarter of 2013. Our Adjusted EBITDA for the six months ended June 30, 2013 was $81.4 million, an increase of 65% from an Adjusted EBITDA of $49.3 million reported for the six months ended June 30, 2012. Our Adjusted EBITDA of $81.4 million for the six months ended June 30, 2013 increased 22% sequentially, as compared to $66.7 million for the six months ended December 31, 2012.

We realized a weighted average oil price of $99.77 per Bbl for the three months ended June 30, 2013, as compared to $103.29 per Bbl for the three months ended June 30, 2012 and $105.72 per Bbl during the first quarter of 2013. This weighted average oil price of $99.77 per Bbl represented an uplift of about $9 per Bbl compared to NYMEX West Texas Intermediate oil prices during the second quarter of 2013, as compared to an uplift of $10 to $12 per Bbl during the first quarter of 2013. Most of our Eagle Ford oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. During the second quarter of 2013, the differential between Louisiana Light Sweet and West Texas Intermediate oil prices narrowed as compared to the first quarter of 2013, and subsequent to June 30, 2013, the price differential between these two benchmark prices has continued to narrow. As a result, we may not realize similar uplifts to West Texas Intermediate oil prices in future periods.

At June 30, 2013, our estimated total proved oil and natural gas reserves were 38.9 million BOE, including 12.1 million Bbl of oil and 160.8 Bcf of natural gas (26.8 million BOE), with a PV-10 of $522.3 million and a Standardized Measure of $477.6 million. At December 31, 2012, our estimated proved oil and natural gas reserves were 23.8 million BOE, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas, and at June 30, 2012, our estimated proved oil and natural gas reserves were 19.1 million BOE, including 6.7 million Bbl of oil and 73.9 Bcf of natural gas. Our proved oil reserves of 12.1 million Bbl at June 30, 2013 increased 80%, as compared to 6.7 million Bbl at June 30, 2012 and 16%, as compared to 10.5 million Bbl at December 31, 2012. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

The unweighted arithmetic average of the first-day-of-the-month natural gas price for the period from July 2012 through June 2013 increased to $3.444 per MMBtu, as compared to $2.757 per MMBtu for the period from January 2012 through December 2012 and $3.146 per MMBtu for the period from July 2011 through June 2012. As a result of the improvement in natural gas prices over the past year, we added approximately 80.1 Bcf (13.3 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our total proved reserves at June 30, 2013, most of which are attributable to non-operated properties. We had removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the natural gas price of $3.146 per MMBtu used to estimate natural gas reserves at June 30, 2012 had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves.

Effective May 8, 2013, we increased our capital expenditure budget for 2013 from $310.0 million to $325.0 million, anticipating the acquisition of additional leasehold interests throughout 2013 above what we had originally budgeted, particularly in Southeast New Mexico and West Texas. We also plan to maintain leasing efforts in the Eagle Ford play and the Haynesville play as opportunities arise. We intend to allocate 78% of our 2013 capital expenditure budget of $325.0 million to the exploration, development and acquisition of additional interests in South Texas, primarily in the Eagle Ford shale play. We also plan to allocate approximately 20% of our 2013 capital expenditure budget to the exploration and acquisition of additional interests in the Wolfcamp, Bone Spring and other oil and liquids-rich plays in Southeast New Mexico and West Texas. As a result of these anticipated capital expenditures in South Texas, Southeast New Mexico and West Texas, we plan to allocate approximately 98% of our 2013 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. Through June 30, 2013, we had incurred approximately $168.6 million, or about 52%, of our 2013 capital expenditure budget of $325.0 million. While we have budgeted $325.0 million for 2013, the aggregate amount of capital we

Table of Contents

will expend may fluctuate materially based on market conditions and our drilling results, as well as other opportunities during the remainder of 2013.

We began the year 2013 with approximately 15,900 gross and 7,600 net acres in Southeast New Mexico and West Texas. Between January 1 and August 8, 2013, we acquired an additional 30,200 gross and 20,700 net acres in this area, primarily in Lea and Eddy Counties, New Mexico. Including these acreage acquisitions, at August 8, 2013, our total acreage position in Southeast New Mexico and West Texas was approximately 46,000 gross and 28,300 net acres, of which we consider 38,300 gross and 26,300 net acres to be prospective for multiple oil and liquids-rich targets, including the Wolfcamp and Bone Spring plays. We expect to continue adding to our leasehold position in Southeast New Mexico and West Texas throughout the remainder of 2013.

As we continue to explore and develop our leasehold positions in the Eagle Ford shale in South Texas and as we begin to explore and develop our leasehold positions in the Wolfcamp, Bone Spring and other plays in Southeast New Mexico and West Texas, we may face challenges in establishing operations in new areas, including securing the necessary services to drill and complete wells and securing the necessary facilities to gather, process, transport and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout these areas, as we have experienced at times in South Texas. We believe that 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, in particular, hydraulic fracturing services for our newly drilled wells during the six months ended June 30, 2013 or during the year ended December 31, 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. In late April 2013, we initiated our drilling operations in Southeast New Mexico, and at August 8, 2013, we have not experienced unusual difficulties in securing the necessary drilling and completion services for our operations. Industry activity in Southeast New Mexico and West Texas is increasing rapidly, however, and we may encounter such difficulties as we move forward with our exploration and development operations in this area in future periods.

We did not experience any significant pipeline interruptions in South Texas during the six months ended June 30, 2013, although we experienced temporary pipeline interruptions from time to time during the year ended December 31, 2012 associated with natural gas production from our Eagle Ford shale wells. To alleviate most of the interruptions and processing capacity constraints we experienced during 2012, effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement whereby we committed to transport the anticipated natural gas production from a significant portion of our Eagle Ford acreage in South Texas through the counterparty’s system for processing at the counterparty’s facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty’s processing plant downstream for fractionation. No assurance can be made that this agreement will alleviate these issues completely, and if we were required to shut in our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it would have a material adverse effect on our business, financial condition, results of operations and cash flows. We may experience similar interruptions and processing capacity constraints as we continue to explore and develop our leasehold position in Southeast New Mexico and West Texas during 2013.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at June 30, 2013, December 31, 2012 and June 30, 2012. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Eagle Ford shale in South Texas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines 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 would 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 quantities of oil and natural gas 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 proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Table of Contents

	June 30, (1) 2013	December 31, (1) 2012	June 30, (1) 2012
Estimated Proved Reserves Data:(2)			
Estimated proved reserves:			
Oil (MBbl)(3)	12,128	10,485	6,728
Natural Gas (Bcf)(4)	160.8	80.0	73.9
Total (MBOE)(5)	38,931	23,819	19,052
Estimated proved developed reserves:			
Oil (MBbl)(3)	6,591	4,764	3,133
Natural Gas (Bcf)(4)	57.8	54.0	54.0
Total (MBOE)(5)	16,221	13,771	12,130
Percent developed	41.7 %	57.8 %	63.7 %
Estimated proved undeveloped reserves:			
Oil (MBbl)(3)	5,537	5,721	3,595
Natural Gas (Bcf)(4)	103.0	26.0	20.0
Total (MBOE)(5)	22,710	10,048	6,922
PV-10(6) (in millions)	$522.3	$423.2	$303.4
Standardized Measure(7) (in millions)	$477.6	$394.6	$281.5

---

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

(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 July 2012 through June 2013 were $88.13 per Bbl for oil and $3.444 per MMBtu for natural gas, for the period January 2012 through December 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas and for the period July 2011 through June 2012 were $92.17 per Bbl for oil and $3.146 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. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) One thousand barrels of oil.

(4) As a result of substantially lower natural gas prices in 2012, at June 30, 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves, most of which were attributable to non-operated properties. At June 30, 2013, as a result of improved natural gas prices in the period from July 2012 through June 2013, we added 80.1 Bcf (13.3 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our total proved reserves, the majority of which are attributable to non-operated properties.

(5) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(6) 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 June 30, 2013, December 31, 2012 and June 30, 2012 may be reconciled to the 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 June 30, 2013,

December 31, 2012 and June 30, 2012 were, in millions, $44.7, $28.6 and $21.9, respectively.

(7) 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

Table of Contents

to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

At June 30, 2013, our estimated total proved oil and natural gas reserves were 38.9 million BOE, including 12.1 million Bbl of oil and 160.8 Bcf of natural gas (26.8 million BOE), with a PV-10 of $522.3 million and a Standardized Measure of $477.6 million. At December 31, 2012, our estimated proved oil and natural gas reserves were 23.8 million BOE, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas, and at June 30, 2012, our estimated proved oil and natural gas reserves were 19.1 million BOE, including 6.7 million Bbl of oil and 73.9 Bcf of natural gas. Our proved oil reserves of 12.1 million Bbl at June 30, 2013 increased 80%, as compared to 6.7 million Bbl at June 30, 2012 and 16%, as compared to 10.5 million Bbl at December 31, 2012. During the six months ended June 30, 2013, our proved developed reserves increased 18% from 13.8 million BOE at December 31, 2012 to 16.2 million BOE at June 30, 2013. Year-over-year, our proved developed reserves increased 34% from 12.1 million BOE at June 30, 2012. At June 30, 2013, approximately 42% of our total proved reserves were proved developed reserves, 31% of our total proved reserves were oil and 69% of our total proved reserves were natural gas.

The unweighted arithmetic average of the first-day-of-the-month natural gas price for the period from July 2012 through June 2013 increased to $3.444 per MMBtu as compared to $2.757 per MMBtu for the period from January 2012 through December 2012 and $3.146 per MMBtu for the period from July 2011 through June 2012. As a result of the improvement in natural gas prices over the past year, we added approximately 80.1 Bcf (13.3 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our total proved reserves at June 30, 2013, most of which are attributable to non-operated properties. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012, because the unweighted arithmetic average natural gas price of $3.146 per MMBtu used to estimate natural gas reserves at June 30, 2012 had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves. Solely as a result of including this additional 80.1 Bcf (13.3 million BOE) of proved undeveloped natural gas reserves in our total proved reserves at June 30, 2013, the percentage of our proved reserves that are proved developed and the percentage of our proved reserves that are oil at June 30, 2013 declined from recent periods.

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 the Annual Report.

Critical Accounting Policies

There have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Recent Accounting Pronouncements

There have been no additional recent accounting pronouncements impacting our financial reporting from those set forth in the Annual Report.

Table of Contents

Results of Operations

Revenues

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013 (Unaudited)	2012 (Unaudited)	2013 (Unaudited)	2012 (Unaudited)
Operating Data:				
Revenues (in thousands):(1)				
Oil	$44,632	$29,426	$93,302	$50,973
Natural gas	13,547	6,652	24,196	14,269
Total oil and natural gas revenues	58,179	36,078	117,498	65,242
Realized gain on derivatives	254	4,713	646	7,776
Unrealized gain on derivatives	7,526	15,114	2,701	11,844
Total revenues	$65,959	$55,905	$120,845	$84,862
Net Production Volumes:(1)				
Oil (MBbl)(2)	447	285	908	485
Natural gas (Bcf)	3.1	3.1	6.2	6.2
Total oil equivalent (MBOE)(3)	963	795	1,944	1,525
Average daily production (BOE/d)(3)	10,582	8,738	10,739	8,380
Average Sales Prices:				
Oil, with realized derivatives (per Bbl)	$99.26	$105.82	$102.27	$106.54
Oil, without realized derivatives (per Bbl)	$99.77	$103.29	$102.78	$105.06
Natural gas, with realized derivatives (per Mcf)	$4.53	$3.48	$4.07	$3.42
Natural gas, without realized derivatives (per Mcf)	$4.38	$2.17	$3.89	$2.29

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with extracted natural gas liquids are included with our natural gas revenues.

(2) One thousand barrels of oil.

(3) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $22.1 million to approximately $58.2 million, or an increase of 61% for the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. This increase in oil and natural gas revenues includes an increase in our oil revenues of $15.2 million and an increase in our natural gas revenues of $6.9 million for the three months ended June 30, 2013, as compared to the comparable period in 2012. Our oil revenues increased 52% to $44.6 million for the three months ended June 30, 2013, as compared to $29.4 million for the three months ended June 30, 2012. This increase in oil revenues reflects the increase in our oil production by 57% to approximately 447 MBbl of oil in the second quarter of 2013, or about 4,916 Bbl of oil per day, as compared to approximately 285 MBbl of oil produced, or about 3,130 Bbl of oil per day, in the second quarter of 2012. This increase in oil production is attributable to our drilling operations in the Eagle Ford shale. The weighted average oil price of $99.77 per Bbl that we realized for the three months ended June 30, 2013 was comparable to, but slightly less than, the weighted average oil price of $103.29 that we realized for the three months ended June 30, 2012. The increase in natural gas revenues on essentially flat natural gas production between the respective periods resulted primarily from a higher weighted average natural gas price of $4.38 per Mcf realized during the second quarter of 2013, as compared to a weighted average natural gas price of $2.17 per Mcf realized during the second quarter of 2012.

Realized gain on derivatives. Our realized gain on derivatives decreased by approximately $4.4 million to $0.3 million for the three months ended June 30, 2013, as compared to $4.7 million for the three months ended June 30, 2012. For the three months ended June 30, 2013, we realized a net gain of approximately $0.1 million and $0.4 million attributable to our natural gas and NGL derivative contracts, respectively, and we realized a net loss of approximately $0.2 million attributable to our oil derivative contracts. For the three months ended June 30, 2012, we realized a net gain of approximately $4.0 million and $0.7

million on our natural gas and oil derivative contracts, respectively. The decreased gain realized from our open natural gas derivative contracts during the respective periods resulted from higher natural gas prices during the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. We realized approximately $0.05 per MMBtu hedged on all of our open natural gas derivative contracts during the three months ended June 30, 2013, as compared to $2.22 per MMBtu hedged on all of our open natural gas derivative contracts during the three months ended June 30, 2012. Our total natural gas volumes hedged for the three months ended June 30, 2013 were 25% higher than the total natural gas volumes hedged for the same period in 2012. In addition, during the second quarter of 2013, our open natural gas costless collar contracts had average floor and ceiling prices of $3.43 per MMBtu and $4.74 per MMBtu, respectively, compared to $4.44 per MMBtu and $5.78 per MMBtu, respectively, during the second quarter of 2012. We realized a net gain of approximately $0.7 million on our open oil derivative contracts during the three months ended June 30, 2012. The net loss on derivatives realized from our open oil derivative contracts during the three months ended June 30, 2013 resulted primarily from oil prices that were in excess of the fixed prices in our open oil swap contracts. We had no open NGL derivative contracts during the three months ended June 30, 2012.

Unrealized gain on derivatives. Our unrealized gain on derivatives was approximately $7.5 million for the three months ended June 30, 2013, as compared to an unrealized gain of approximately $15.1 million for the three months ended June 30, 2012. During the period from March 31, 2013 to June 30, 2013, the net fair value of our open oil, natural gas and NGL derivative contracts increased from approximately $(0.3) million to approximately $7.2 million, resulting in an unrealized gain on derivatives of approximately $7.5 million for the three months ended June 30, 2013. The net fair value of our open derivative contracts for each commodity—oil, natural gas and natural gas liquids—increased at June 30, 2013 compared to March 31, 2013 due to declines in futures prices for each commodity at June 30, 2013, as compared to futures prices at March 31, 2013. During the period from March 31, 2012 to June 30, 2012, the net fair value of our open oil and natural gas derivative contracts increased from $6.0 million to $21.1 million, resulting in an unrealized gain on derivatives of $15.1 million for the three months ended June 30, 2012. We had no open NGL contracts during the three months ended June 30, 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

Oil and natural gas revenues. Our oil and natural gas revenues increased by approximately $52.3 million to approximately $117.5 million, or an increase of about 80% for the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. This increase in oil and natural gas revenues includes an increase in our oil revenues of $42.3 million and an increase in our natural gas revenues of $9.9 million for the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. Our oil revenues increased by 83% to $93.3 million for the six months ended June 30, 2013, as compared to $51.0 million for the six months ended June 30, 2012. This increase reflects the increase in our oil production by 87% to 908 MBbl of oil in the six months ended June 30, 2013, or about 5,015 Bbl of oil per day, as compared to approximately 485 MBbl of oil produced, or about 2,670 Bbl of oil per day, in the six months ended June 30, 2012. This increased oil production is attributable to our drilling operations in the Eagle Ford shale. The weighted average oil price of $102.78 per Bbl realized for the six months ended June 30, 2013 was comparable to, but slightly less than, the weighted average oil price of $105.06 per Bbl that we realized for the six months ended June 30, 2012. The increase in natural gas revenues on relatively flat natural gas production between the respective periods resulted from a higher weighted average natural gas price of $3.89 per Mcf realized during the six months ended June 30, 2013, as compared to a weighted average natural gas price of $2.29 per Mcf realized during the six months ended June 30, 2012.

Realized gain on derivatives. Our realized gain on derivatives decreased by approximately $7.1 million to $0.6 million for the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. For the six months ended June 30, 2013, we realized a net gain of approximately $0.6 million and $0.5 million attributable to our natural gas and NGL derivative contracts, respectively, and we realized a net loss of approximately $0.5 million attributable to our oil derivative contracts. For the six months ended June 30, 2012, we realized a net gain of approximately $7.1 million and $0.7 million attributable to our natural gas and oil derivative contracts, respectively. The decreased gain realized from our natural gas derivative contracts resulted from higher natural gas prices during the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. We realized approximately

$0.17 per MMBtu hedged on all of our open natural gas derivative contracts during the six months ended June 30, 2013, as compared to $1.96 per MMBtu hedged on all of our open natural gas derivatives contracts during the six months ended June 30, 2012. Our total natural gas volumes hedged for the six months ended June 30, 2013 were unchanged compared to our total natural gas volumes hedged for the six months ended June 30, 2012. In addition, for the six months ended June 30, 2013, our open natural gas costless collar contracts had average floor and ceiling prices of $3.46 per MMBtu and $4.83 per MMBtu, respectively, compared to $4.44 per MMBtu and $5.78 per MMBtu, respectively, for the six months ended June 30, 2012. The net loss on derivatives realized from our open oil derivative contracts during the six months ended June 30, 2013 resulted primarily from oil prices that were in excess of the fixed prices in our open oil swap contracts. We had no open NGL contracts during the six months ended June 30, 2012.

Table of Contents

Unrealized gain on derivatives. Our unrealized gain on derivatives was approximately $2.7 million for the six months ended June 30, 2013, as compared to an unrealized gain of $11.8 million for the six months ended June 30, 2012. During the period from December 31, 2012 through June 30, 2013, the net fair value of our open oil, natural gas and NGL derivative contracts increased from approximately $4.5 million to approximately $7.2 million, resulting in an unrealized gain on derivatives of approximately $2.7 million for the six months ended June 30, 2013. This gain is primarily attributable to an increase in the net fair value of our open oil and NGL contracts for the six months ended June 30, 2013. This increase was due to a decline in NGL prices, which increased the net fair value of our open NGL contracts by approximately $1.6 million between December 31, 2012 and June 30, 2013 and a decline in oil prices and an increase in the total oil volumes hedged at June 30, 2013, as compared to December 31, 2012, which increased the net fair value of our open oil contracts by approximately $1.3 million for the six months ended June 30, 2013. During the period from December 31, 2011 through June 30, 2012, the net fair value of our open oil and natural gas derivative contracts increased from $9.3 million to $21.1 million, resulting in an unrealized gain on derivatives of $11.8 million for the six months ended June 30, 2012. We had no open NGL contracts during the six months ended June 30, 2012.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
(In thousands, except expenses per BOE)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
Expenses:				
Production taxes and marketing	$4,451	$2,619	$8,548	$4,783
Lease operating	10,140	6,375	21,040	11,020
Depletion, depreciation and amortization	20,234	19,913	48,466	31,119
Accretion of asset retirement obligations	80	58	161	111
Full-cost ceiling impairment	—	33,205	21,229	33,205
General and administrative	4,149	4,093	8,751	7,882
Total expenses	39,054	66,263	108,195	88,120
Operating income (loss)	26,905	(10,358)	12,650	(3,258)
Other income (expense):				
Net loss on asset sales and inventory impairment	(192)	(60)	(192)	(60)
Interest expense	(1,609)	(1)	(2,880)	(309)
Interest and other income	47	30	115	103
Total other expense	(1,754)	(31)	(2,957)	(266)
Income (loss) before income taxes	25,151	(10,389)	9,693	(3,524)
Total income tax provision (benefit)	32	(3,713)	78	(649)
Net income (loss)	$25,119	$(6,676)	9,615	$(2,875)
Expenses per BOE:				
Production taxes and marketing	$4.62	$3.29	$4.40	$3.14
Lease operating	$10.53	$8.02	$10.82	$7.23
Depletion, depreciation and amortization	$21.01	$25.04	$24.93	$20.40
General and administrative	$4.31	$5.15	$4.50	$5.17

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $1.8 million to approximately $4.5 million, or an increase of approximately 70%, for the three months ended June 30, 2013, as compared to $2.6 million for the three months ended June 30, 2012. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by approximately 61% during the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. The majority of this increase was attributable to production taxes associated with the large increase in oil production and associated oil revenues during the three months ended June 30, 2013 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 46% oil and 54% natural gas for the three months ended June 30, 2013, as compared to approximately 36% oil and 64% natural gas during the same period in 2012. On a unit-of-production basis, our production taxes and marketing

Table of Contents

expenses increased by 40% to $4.62 per BOE for the three months ended June 30, 2013, as compared to $3.29 per BOE for the three months ended June 30, 2012.

Lease operating expenses. Our lease operating expenses increased by approximately $3.8 million to approximately $10.1 million, or an increase of 59%, for the three months ended June 30, 2013, as compared to approximately $6.4 million for the three months ended June 30, 2012. During these respective periods, our total oil and natural gas production increased about 21% to 963 MBOE from 795 MBOE, including an increase in oil production of 57% to approximately 447 MBbl of oil from approximately 285 MBbl of oil. Our lease operating expenses per unit of production increased approximately 31% to $10.53 per BOE for the three months ended June 30, 2013, as compared to $8.02 per BOE for the three months ended June 30, 2012. This increase in lease operating expenses was primarily attributable to the overall increase in oil production and the higher lifting costs associated with oil production between the comparable periods, as well as to the increased percentage of oil being produced, which was 46% of total production by volume in the second quarter of 2013, compared to only 36% of total production by volume in the second quarter of 2012.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $0.3 million to $20.2 million, or an increase of about 2%, for the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. On a unit-of-production basis, our depletion, depreciation and amortization expenses decreased to $21.01 per BOE for the three months ended June 30, 2013, or a decrease of about 16%, from $25.04 per BOE for the three months ended June 30, 2012. The decrease in our depletion, depreciation and amortization expenses occurred despite an increase of approximately 21% in our total oil and natural gas production to 963 MBOE from 795 MBOE during the respective periods. Because we use the unit-of-production method for calculating depletion, depreciation and amortization, the impact of the increased production experienced in the three months ended June 30, 2013, as compared to the three months ended June 30, 2012, on our depletion, depreciation and amortization expenses was partially offset by the increase in our proved oil and natural gas reserves to 38.9 million BOE at June 30, 2013 from 19.1 million BOE at June 30, 2012. As a result of the improvement in natural gas prices over the past year, we added approximately 80.1 Bcf (13.3 million BOE) of proved undeveloped natural gas reserves in the Haynesville Shale in Northwest Louisiana to our total proved reserves at June 30, 2013, most of which are attributable to non-operated properties. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the unweighted arithmetic average natural gas price of $3.146 per MMBtu had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville Shale locations could no longer be classified as proved undeveloped reserves.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $22,000 to approximately $80,000, or an increase of about 38%, for the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. 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. No impairment to the net carrying value of our oil and natural gas properties on the unaudited condensed consolidated balance sheet, and no corresponding charge to the unaudited condensed consolidated statement of operations, resulting from a full-cost ceiling impairment was recorded during the three months ended June 30, 2013. 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 three months ended June 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices in the twelve-month period prior to June 30, 2012, resulting in the removal of 97.8 Bcf 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.

General and administrative. Our general and administrative expenses remained flat at $4.1 million for the three months ended June 30, 2013 and 2012. Our general and administrative expenses decreased by approximately 16% on a unit-of-production basis to $4.31 per BOE for the three months ended June 30, 2013, as compared to $5.15 per BOE for the three months ended June 30, 2012. This decrease on a unit-of-production basis was attributable to the increase of approximately 21% in our total oil and natural gas production between the respective periods. While our total general and administrative expenses of $4.1 million for the three months ended June 30, 2013 remained flat when compared to the total general and administrative expenses for the three months ended June 30, 2012, we did experience an increase in stock-based compensation costs of $0.8 million to $1.0 million for the three months ended June 30, 2013, as compared to $0.2 million for the three months ended June 30, 2012. This increase in our stock-based compensation expense is attributable to the continued vesting of awards granted in 2012 and 2013, as well as the increased fair value of our liability-based stock options. This increase was partially offset by a decrease in our general and administrative expenses of approximately $1.0 million during the second quarter of 2013 as we allocated and capitalized a portion of our general and administrative expenses to the permanent production facilities being constructed on certain of our properties in the Eagle Ford shale in South Texas.

Net loss on asset sales and inventory impairment. During the three months ended June 30, 2013, we recorded an impairment to some of our pipe held in inventory totaling approximately $192,000. During the three months ended June 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.

Interest expense. For the three months ended June 30, 2013, we incurred total interest expense of approximately $2.1 million. We capitalized approximately $0.5 million of our interest expense on certain qualifying projects for the three months ended June 30, 2013 and expensed the remaining $1.6 million to operations. For the three months ended June 30, 2012, we incurred total interest expense of approximately $0.3 million. We capitalized approximately $0.3 million of our interest expense on certain qualifying projects for the three months ended June 30, 2012 and expensed the small remaining amount to operations. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income increased by approximately $17,000 to approximately $47,000, or an increase of about 56%, for the three months ended June 30, 2013, as compared to the three months ended June 30, 2012. The increase in our interest and other income was due primarily to slight increases in both the transportation income and salt water disposal income we received from third parties during the second quarter of 2013, as compared to the second quarter of 2012, although on the whole, this item is an insignificant component of our overall income. Our cash and certificates of deposit decreased to approximately $5.2 million at June 30, 2013 from approximately $9.7 million at June 30, 2012.

Total income tax provision. Based on our projections for the remainder of 2013, we anticipate incurring a small alternative minimum tax (“AMT”) liability for the year ending December 31, 2013, the proportionate share of which is recorded as the current income tax provision of approximately $32,000 for the three months ended June 30, 2013. The total income tax provision for the three months ended June 30, 2013 represents only our estimate of the AMT liability attributable to the three months ended June 30, 2013, while the income tax provision recorded at June 30, 2012 reflected only deferred income taxes. The Company established a valuation allowance at September 30, 2012 and retained a full valuation allowance of approximately $6.7 million at June 30, 2013 due to uncertainties regarding the future realization of its net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the three months ended June 30, 2013, other than the AMT liability noted above. We recorded a total income tax benefit of approximately $3.7 million for the three months ended June 30, 2012. During the quarter ended June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $21.3 million. We recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred tax credit of $11.9 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 three months ended June 30, 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

Production taxes and marketing. Our production taxes and marketing expenses increased by approximately $3.8 million to approximately $8.5 million, or an increase of approximately 79%, for the six months ended June 30, 2013, as compared to $4.8 million for the six months ended June 30, 2012. The increase in our production taxes and marketing expenses was primarily due to the increase in our oil and natural gas revenues by approximately 80% during the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. The majority of this increase was attributable to production taxes associated with the large increase in oil production and associated oil revenues during the six months ended June 30, 2013 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 47% oil and 53% natural gas for the six months ended June 30, 2013, as compared to approximately 32% oil and 68% natural gas for the six months ended June 30, 2012. On a unit-of-production basis, our production taxes and marketing expenses increased by 40% to $4.40 per BOE for the six months ended June 30, 2013, as compared to $3.14 per BOE for the six months ended June 30, 2012.

Lease operating expenses. Our lease operating expenses increased by approximately $10.0 million to approximately $21.0 million, or an increase of approximately 91%, for the six months ended June 30, 2013, as compared to $11.0 million for the six months ended June 30, 2012. During these respective periods, our total oil and natural gas production increased about 28% to 1.9 million BOE from 1.5 million BOE, including an increase of 87% in oil production to approximately 908 MBbl of oil from approximately 485 MBbl of oil. Our lease operating expenses per unit of production increased approximately 50% to $10.82 per BOE for the six months ended June 30, 2013, as compared to $7.23 per BOE for the six months ended June 30, 2012. This increase in lease operating expenses was primarily attributable to the overall increase in oil production and the higher lifting costs assoicated with oil production between the comparable periods, as well as to the increased percentage of oil

Table of Contents

being produced, which was 47% of total production by volume for the six months ended June 30, 2013, as compared to only 32% of total production by volume for the six months ended June 30, 2012.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $17.3 million to $48.5 million, or an increase of 56% for the six months ended June 30, 2013, as compared to $31.1 million for the six months ended June 30, 2012. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $24.93 per BOE for the six months ended June 30, 2013, or an increase of about 22% from $20.40 per BOE for the six months ended June 30, 2012. This increase in our depletion, depreciation and amortization expenses was attributable to the increase of approximately 27% in our total oil and natural gas production to 1.9 million BOE from 1.5 million BOE during the respective periods, as well as to the higher drilling and completion 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. Because we use the unit-of-production method for calculating depletion, depreciation and amortization, the impact of the increased production experienced in the six months ended June 30, 2013, as compared to the six months ended June 30, 2012, on our depletion, depreciation and amortization expenses was partially offset by the increase in our proved oil and natural gas reserves to 38.9 million BOE at June 30, 2013 from 19.1 million BOE at June 30, 2012. As a result of the improvement in natural gas prices over the past year, we added approximately 80.1 Bcf (13.3 million BOE) of proved undeveloped natural gas reserves in the Haynesville Shale in Northwest Louisiana to our total proved reserves at June 30, 2013, most of which are attributable to non-operated properties. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the unweighted arithmetic average natural gas price of $3.146 per MMBtu had declined to a level that the natural gas volumes associated with almost all of our identified Haynesville Shale locations could no longer be classified as proved undeveloped reserves.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $50,000 to approximately $161,000, or an increase of about 45%, for the six months ended June 30, 2013, as compared to approximately $111,000 for the six months ended June 30, 2012. 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. No impairment to the net carrying value of our oil and natural gas properties on the unaudited condensed consolidated balance sheet, and no corresponding charge to the unaudited condensed consolidated statement of operations, resulting from a full-cost ceiling impairment was recorded during the three months ended June 30, 2013. During the quarter ended March 31, 2013, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $13.7 million. As a result, we recorded an impairment charge of $21.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $7.5 million. This full-cost ceiling impairment of $21.2 million is reflected in our operating expenses for the six months ended June 30, 2013. At March 31, 2013 and at June 30, 2013, we retained a full valuation allowance against our net deferred tax assets, and as a result, no deferred income tax provision is reflected in the unaudited condensed consolidated statement of operations for the six months ended June 30, 2013. 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 three months ended June 30, 2012. This impairment was primarily attributable to the continued decline in natural gas prices in the twelve-month period prior to June 30, 2012, resulting in the removal of 97.8 Bcf 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.

Net loss on asset sales and inventory impairment. During the six months ended June 30, 2013, we recorded an impairment to some of our pipe held in inventory totaling approximately $192,000. During the six months ended June 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.

General and administrative. Our general and administrative expenses increased by $0.9 million to $8.8 million, or an increase of approximately 11%, for the six months ended June 30, 2013, as compared to $7.9 million for the six months ended June 30, 2012. Our general and administrative expenses decreased by approximately 13% on a unit-of-production basis to $4.50 per BOE for the six months ended June 30, 2013, as compared to $5.17 for the six months ended June 30, 2012. The increase in our general and administrative expenses was primarily attributable to an increase in stock-based compensation costs of $1.7 million to $1.5 million for the six months ended June 30, 2013, as compared to $(0.2) million for the six months ended June 30, 2012. This increase in our stock-based compensation expense was attributable to the continued vesting of awards granted in 2012 and 2013, as well as the increased fair value of our liability-based stock options. This increase was partially offset by a decrease in our general and administrative expenses of approximately $1.0 million during the second quarter of 2013 as we allocated and capitalized a portion of our general and administrative expenses to the permanent production facilities being constructed on certain of our properties in the Eagle Ford shale in South Texas.

Interest expense. For the six months ended June 30, 2013, we incurred total interest expense of approximately $3.7 million. We capitalized approximately $0.8 million of our interest expense on certain qualifying projects for the six months ended June 30, 2013 and expensed the remaining $2.9 million to operations. For the six months ended June 30, 2012, we incurred total interest expense of approximately $0.9 million. We capitalized approximately $0.6 million of our interest expense on certain qualifying projects for the six months ended June 30, 2012 and expensed the remaining $0.3 million to operations. As we increase the borrowings under our Credit Agreement, we expect to incur increased interest expense.

Interest and other income. Our interest and other income increased by approximately $12,000 to approximately $115,000, or an increase of approximately 11%, for the six months ended June 30, 2013, as compared to approximately $103,000 for the six months ended June 30, 2012. The increase in our interest and other income was due primarily to slight increases in both the transportation income and salt water disposal income we received from third parties during the six months ended June 30, 2013, as compared to the six months ended June 30, 2012, although on the whole, this item is an insignificant component of our overall income. Our cash and certificates of deposit decreased to approximately $5.2 million at June 30, 2013 from approximately $9.7 million at June 30, 2012.

Total income tax provision (benefit). Based on our projections for the remainder of 2013, we anticipate incurring a small AMT liability for the year ending December 31, 2013, the proportionate share of which is recorded as the current income tax provision of approximately $78,000 for the six months ended June 30, 2013. The total income tax provision for the six months ended June 30, 2013 represents only our estimate of the AMT liability attributable to the six months ended June 30, 2013, while the income tax provision recorded for the six months ended June 30, 2012 reflected only deferred income taxes. The Company established a valuation allowance at September 30, 2012 and retained a full valuation allowance of approximately $6.7 million at June 30, 2013 due to uncertainties regarding the future realization of its net deferred tax assets. As a result, there was no income tax expense or benefit recorded for the six months ended June 30, 2013, other than the AMT liability noted above. We recorded a total income tax benefit of approximately $0.6 million for the six months ended June 30, 2012. During the six months ended June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $21.3 million. We recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred tax credit of $11.9 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 six months ended June 30, 2012. We had a net loss for the six months ended June 30, 2012.

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 2013 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 ventures, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved oil and natural gas reserves and production will be highly dependent on our ability to access outside sources of capital and to continue to grow our operating cash flows.

At June 30, 2013, we had cash and certificates of deposits totaling approximately $5.2 million, the borrowing base under our Credit Agreement was $280.0 million and we had $245.0 million of outstanding long-term borrowings and approximately $1.2 million in outstanding letters of credit. These borrowings bore interest at an effective interest rate of 3.6% per annum. From July 1, 2013 through August 8, 2013, we borrowed an additional $15.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests in Southeast New Mexico.

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. The borrowing base under the Credit Agreement is scheduled to be redetermined automatically on May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates. During the first quarter of 2013, our lenders completed their review of our proved oil and natural gas reserves at December 31, 2012, and as a result, on March 11, 2013, the borrowing base under our Credit Agreement was increased to $255.0 million. The March redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, we requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to $280.0 million, based on the

Table of Contents

lenders' review of our proved oil and natural gas reserves at March 31, 2013 and other then-recently completed wells. On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million from $280.0 million, based on the lenders' review of our proved oil and natural gas reserves at June 30, 2013. This August redetermination constituted the regularly scheduled November 1 redetermination. We may request one additional unscheduled redetermination of the borrowing base prior to the next scheduled redetermination. We expect additional increases to the borrowing base will be primarily as a result of anticipated increases in our proved oil and natural gas reserves, and particularly our proved developed oil and natural gas reserves.

As a result of these anticipated increases in the borrowing base, together with our anticipated increases in oil production and related revenues, we expect to have sufficient cash flows from operations and future borrowing capacity under our Credit Agreement to fund our capital expenditure requirements for the remainder of 2013. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. However, should our drilling activities be less successful than we anticipate or result in less growth in our proved oil and natural gas reserves or less cash flows than we anticipate for the remainder of 2013, or should oil and natural gas prices decline substantially, we may require additional sources of financing, including through additional borrowings under our Credit Agreement or additional credit arrangements, potential joint ventures and potential issuances of equity or debt securities, which may not be available on terms reasonably acceptable to us or at all. To the extent such sources of financing are not available on terms reasonably acceptable to us, we may need to reduce our capital spending and rate of growth.

Although a majority of our anticipated increase in cash flows from operations during the year ending December 31, 2013, as compared to our cash flows from operations in prior periods, is expected to come from development activities on proved properties in the Eagle Ford shale play at December 31, 2012, these development activities may be less successful than we anticipate. Further, a portion of our anticipated increase in cash flows from operations during the year ending December 31, 2013 is expected to come from exploration activities on currently unproved properties in the Eagle Ford shale in South Texas and in the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas, and these exploration activities may not be as successful as we anticipate. Additionally, any anticipated increases in our cash flows from operations are based upon current expectations of oil and natural gas prices for the remainder of 2013 and the hedges we currently have in place. If our exploration and development activities result in less cash flows than anticipated, we may seek additional sources of capital, including through additional borrowings under our Credit Agreement (assuming availability under our borrowing base), the establishment of additional credit arrangements, the sale of debt securities, the sale of assets or acreage or entering into one or more joint ventures, none of which may be available on terms acceptable to us or at all. In addition to these potential sources of capital, we may also seek to raise 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 markets or otherwise. It is likely that any such sales would dilute the ownership interest of our existing shareholders. There is no guarantee that we would be able to sell such debt or equity securities on terms acceptable to us or at all. It is also possible that, to the extent we are not able to obtain additional sources of capital, we may modify our planned capital expenditure budget for 2013 accordingly. Exploration and development 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.

Our cash flows for the six months ended June 30, 2013 and 2012 are presented below:

	Six Months Ended June 30,	
	2013	2012
(In thousands)	(Unaudited)	(Unaudited)
Net cash provided by operating activities	$83,912	$51,526
Net cash used in investing activities	(175,901)	(136,877)
Net cash provided by financing activities	94,999	84,499

Net change in cash	$3,010	$(852)
Adjusted EBITDA[1]	$81,444	$49,264

(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.

41

Table of Contents

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by approximately $32.4 million to $83.9 million for the six months ended June 30, 2013, as compared to net cash provided by operating activities of $51.5 million for the six months ended June 30, 2012. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $78.5 million for the six months ended June 30, 2013 from $49.0 million for the six months ended June 30, 2012. This increase is primarily attributable to the 87% increase in our oil production to approximately 908 MBbl from approximately 485 MBbl during the respective periods as a result of our ongoing operations in the Eagle Ford shale. Changes in our operating assets and liabilities between June 30, 2012 and June 30, 2013 also resulted in a net increase of approximately $2.9 million in net cash provided by operating activities for the six months ended June 30, 2013, as compared to the six months ended June 30, 2012.

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. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by approximately $39.0 million to $175.9 million for the six months ended June 30, 2013 from $136.9 million for the six months ended June 30, 2012. This increase in net cash used in investing activities is almost entirely attributable to the increase in cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. Cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2013 was primarily attributable to our operated drilling and completion activities in the Eagle Ford shale play in South Texas and the acquisition of additional leasehold interests in Southeast New Mexico and West Texas.

Effective May 8, 2013, we increased our capital expenditure budget for 2013 from $310.0 million to $325.0 million, as we anticipate the acquisition of additional leasehold interests throughout 2013, particularly in Southeast New Mexico and West Texas. We also plan to maintain leasing efforts in the Eagle Ford play and the Haynesville play as opportunities arise. Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing $325.0 million in capital for acquisition, exploration and development activities in 2013 as follows:

	Amount (in millions)
Exploration, development drilling and completion costs	$260.0
Pipeline and infrastructure expenditures	25.0
Leasehold acquisition and 2-D and 3-D seismic data	40.0
Total	$325.0

At June 30, 2013, we had incurred approximately $168.6 million, or about 52%, of our 2013 capital expenditure budget of $325.0 million. Overall, at June 30, 2013, we are executing our 2013 capital expenditure program largely as planned and remain within our capital expenditure budget for 2013. While we have budgeted $325.0 million for 2013, 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 2013.

For further information regarding our anticipated capital expenditure budget in 2013, see "Business – General" in the Annual Report. Our 2013 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.

Table of Contents

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $95.0 million for the six months ended June 30, 2013, as compared to net cash provided by financing activities of $84.5 million for the six months ended June 30, 2012. The net cash provided by financing activities for the six months ended June 30, 2013 was attributable to borrowings under our Credit Agreement. The net cash provided by financing activities for the six months ended June 30, 2012 was principally due to the total proceeds from our initial public offering of $146.5 million and incremental borrowings of $70.0 million, 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 six months ended June 30, 2012.

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, 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.

	Six Months Ended June 30,	
(In thousands)	2013	2012
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):		
Net income (loss)	$9,615	$(2,875)
Interest expense	2,880	309
Total income tax provision (benefit)	78	(649)
Depletion, depreciation and amortization	48,466	31,119
Accretion of asset retirement obligations	161	111
Full-cost ceiling impairment	21,229	33,205
Unrealized gain on derivatives	(2,701)	(11,844)
Stock-based compensation expense	1,524	(172)
Net loss on asset sales and inventory impairment	192	60
Adjusted EBITDA	$81,444	$49,264

43

Table of Contents

(In thousands)	Six Months Ended June 30, 2013	2012
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:		
Net cash provided by operating activities	$ 83,912	$ 51,526
Net change in operating assets and liabilities	(5,426)	(2,571)
Interest expense	2,880	309
Current income tax provision	78	—
Adjusted EBITDA	$ 81,444	$ 49,264

Our Adjusted EBITDA increased by approximately $32.2 million to approximately $81.4 million, or an increase of approximately 65% for the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. 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 six months ended June 30, 2013, as compared to the six months ended June 30, 2012.

Credit Agreement

On September 28, 2012, we amended and restated our revolving credit agreement. This third amended and restated credit agreement (the “Credit Agreement”) increased the maximum facility amount from $400.0 million to $500.0 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, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by the eligible 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 our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2013, the lenders completed their review of our proved oil and natural gas reserves at December 31, 2012, and on March 11, 2013, the borrowing base was increased from $215.0 million to $255.0 million. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $220.0 million. At that time, we also amended the Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and Iberia Bank in our lending group, which also includes RBC as administrative agent, Comerica Bank, Citibank, N.A., the Bank of Nova Scotia and SunTrust Bank. This March 11, 2013 redetermination constituted the regulary scheduled May 1 redetermination. In late April 2013, we requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to $280.0 million, and the conforming borrowing base was increased to $245.0 million.

On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million and the conforming borrowing base was increased to $275.0 million. At that time, we amended the Credit Agreement to provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by us of senior unsecured notes in an amount greater than or equal to $10.0 million. This August redetermination constituted the regularly scheduled November 1 redetermination. We may request one additional unscheduled redetermination of our borrowing base prior to the next scheduled redetermination.

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 is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, 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. Between January 1, 2013 and June 30, 2013, we borrowed $95.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At June 30, 2013, we had $245.0 million in borrowings outstanding under the Credit Agreement and approximately $1.2 million in outstanding letters of credit issued pursuant to the Credit Agreement. At June 30, 2013, our outstanding borrowings bore interest at an effective interest rate of approximately 3.6% per annum. We expect to access future borrowings under our Credit Agreement to fund a portion of our 2013 capital

Table of Contents

expenditure requirements in excess of amounts available from our operating 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, and particularly our proved developed oil and natural gas reserves, primarily attributable to our ongoing drilling operations in the Eagle Ford shale. From June 30, 2013 through August 8, 2013, we borrowed an additional $15.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests in Southeast New Mexico. At August 8, 2013, we had $260.0 million in borrowings outstanding under the Credit Agreement and approximately $1.2 million in outstanding letters of credit issued pursuant to the Credit Agreement.

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 3.00% 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 4.00% 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 us. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. We include this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees as interest expense and in our interest rate calculations and related disclosures.

Key financial covenants under the Credit Agreement require us 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 June 30, 2014 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, 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 amounts 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 June 30, 2013, we believe that we were in compliance with the terms of our Credit Agreement.

Off-Balance Sheet Arrangements

At June 30, 2013, we did not have any off-balance sheet arrangements.

Table of Contents

Obligations and Commitments

We had the following material contractual obligations and commitments at June 30, 2013:

	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]	$246,195	$1,195	$—	$245,000	$—
Office lease	7,956	773	1,664	1,744	3,775
Non-operated drilling commitments[2]	6,598	6,598	—	—	—
Drilling rig contracts[3]	2,012	2,012	—	—	—
Asset retirement obligations	6,685	804	382	606	4,893
Gas processing agreement[4]	13,735	5,735	5,900	2,100	—
Total contractual cash obligations	$283,181	$17,117	$7,946	$249,450	$8,668

(1) At June 30, 2013, we had $245.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $1.2 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 June 30, 2013, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and most of these wells were in progress at June 30, 2013. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $6.6 million at June 30, 2013, which we expect to incur within the next few months.

(3) From time to time, we enter into contracts with third parties for drilling rigs. These contracts establish daily rates for the drilling rigs and the term of our commitments for the drilling services to be provided, which are typically for one year or less. Should we elect to terminate a contract and if the drilling contractor were unable to secure work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling 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 our drilling rig contracts were approximately $2.0 million at June 30, 2013. In July 2013, we entered into a contract for an additional drilling rig to continue to explore and develop our acreage in the Eagle Ford shale in South Texas. Drilling operations under this contract are scheduled to commence in late August 2013 and the term of the contract is 180 days from the commencement date. Should we elect to terminate this contract and if the drilling contractor were unable to secure work for the rig or if the drilling contractor were unable to secure work for the rig at the same daily rate being charged to us, we would incur termination obligations. Our maximum termination obligation under this contract was approximately $2.7 million at August 8, 2013.

(4) Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement for a significant portion of our operated natural gas production in South Texas. The undiscounted minimum commitments under this agreement total approximately $13.7 million at June 30, 2013.

General Outlook and Trends

For the six months ended June 30, 2013, oil prices ranged from a high of approximately $98.44 per Bbl in mid-June to a low of approximately $86.68 per Bbl in mid-April, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized an average oil price of $102.78 per Bbl ($102.27 per Bbl including realized losses from oil derivatives) for our oil production for the six months ended June 30, 2013, as compared to $105.06 per Bbl ($106.54 per Bbl including realized gains from oil derivatives) for the six months ended June 30, 2012. Subsequent to June 30, 2013, oil prices have increased and at August 8, 2013, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $103.40 per Bbl as compared to $93.35 per Bbl at August 8, 2012.

We realized a weighted average oil price of $99.77 per Bbl for the three months ended June 30, 2013, which represented an uplift of about $9 per Bbl compared to NYMEX West Texas Intermediate oil prices during the second quarter of 2013, as compared to an uplift of $10 to $12 per Bbl during the first quarter of 2013. Most of our Eagle Ford oil production in South

Table of Contents

Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. During the second quarter of 2013, the differential between Louisiana Light Sweet and West Texas Intermediate oil prices narrowed as compared to the first quarter of 2013, and subsequent to June 30, 2013, the price differential between these two benchmarks has continued to narrow. As a result, we may not realize similar uplifts to West Texas Intermediate oil prices in future periods.

For the six months ended June 30, 2013, natural gas prices ranged from a low of approximately $3.11 per MMBtu in early January to a high of approximately $4.41 per MMBtu in mid-April, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a natural gas price of $3.89 per Mcf ($4.07 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the six months ended June 30, 2013, as compared to $2.29 per Mcf ($3.42 per Mcf including realized gains from natural gas derivatives) for the six months ended June 30, 2012. Since their 2013 high in mid-April, natural gas prices have declined somewhat, and at August 8, 2013, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $3.30 per MMBtu, as compared to $2.93 per MMBtu at August 8, 2012.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenues, profitability, cash flows available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and natural gas liquids 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, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or natural gas liquids prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and natural gas liquids we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. Even so, decisions as to whether and what volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. Should oil, natural gas or natural gas liquids 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 anticipate similar rapid initial production declines in wells we complete in the Wolfcamp and Bone Spring plays as well. 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, natural gas and natural gas liquids 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, cash flows and availability under our Credit Agreement.

We must focus our efforts on increasing oil and natural 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 and in the Annual Report, there have been no changes to our market risk since December 31, 2012.

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 anticipated future production.

We use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and natural gas liquids prices. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified time, providing downside price protection.

Table of Contents

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. At June 30, 2013, Comerica Bank, RBC and The Bank of Nova Scotia (or affiliates thereof) were the counterparties for all of our derivative instruments. We have evaluated the credit standing of the counterparties in determining the fair value of our derivative financial instruments.

We have entered into various costless collar contracts to mitigate our exposure to fluctuations in oil prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss 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 one or more of 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 one or more of 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 oil volume.

We have also entered into various swap contracts to mitigate our exposure to fluctuations in oil prices, each with an established fixed price. For each calculation period, the specified price for determining the realized gain or loss pursuant to any of these transactions is the arithmetic average of the settlement prices for 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 fixed price established by one or more of 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 oil volume. When the settlement price is above the fixed price established by one or more of these swaps, we pay to our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume.

We have entered into various costless collar transactions for natural gas, 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 one or more of 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 one or more of 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.

We have entered into various swap contracts to mitigate our exposure to fluctuations in natural gas liquids ("NGL") prices, 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, except for purity ethane, as stated on the "Mont Belvieu Spot Gas Liquids Prices: NON-TET prop" on the pricing date. The settlement price for purity ethane is the arithmetic average of any current month for delivery on the nearby month futures contracts as stated on the "Mont Belvieu Spot Gas Liquids Prices" on the pricing date. When the settlement price is below the fixed price established by one or more of 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 one or more of these swaps, we pay to our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At June 30, 2013, we had various costless collar contracts open and in place to mitigate our 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 2013, 2014 and 2015.

At June 30, 2013, we had various swap contracts open and in place to mitigate our exposure to oil and 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 2013 and 2014.

48

Table of Contents

The following is a summary of the Company’s open costless collar contracts for oil and natural gas and open swap contracts for oil and natural gas liquids at June 30, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	07/01/2013 - 12/31/2013	20,000	85.00	102.25	$(9)
Oil	07/01/2013 - 12/31/2013	20,000	85.00	108.80	84
Oil	07/01/2013 - 12/31/2013	20,000	85.00	110.40	94
Oil	07/01/2013 - 12/31/2013	20,000	90.00	102.80	126
Oil	07/01/2013 - 12/31/2013	20,000	90.00	115.00	224
Oil	07/01/2013 - 06/30/2014	8,000	90.00	114.00	336
Oil	07/01/2013 - 06/30/2014	12,000	90.00	115.50	513
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	248
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	546
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	349
Oil	01/01/2014 - 12/31/2014	20,000	88.00	95.60	444
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	763
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	642
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	637
Total open oil costless collar contracts					4,997

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	07/01/2013 - 07/31/2013	150,000	4.50	5.75	119
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.00	3.83	(57)
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.00	4.95	9
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.00	4.96	10
Natural Gas	07/01/2013 - 12/31/2013	150,000	3.00	4.24	(25)
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.25	4.41	14
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.25	4.44	16
Natural Gas	07/01/2013 - 12/31/2013	100,000	3.50	4.37	55
Natural Gas	08/01/2013 - 12/31/2013	80,000	3.75	4.57	104
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(26)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	45
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	45
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	64
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	68
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	98
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	200
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	207
Total open natural gas costless collar contracts					946

Table of Contents

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Fixed Price ($/Bbl)	Fair Value of Liability (thousands)
Oil	07/01/2013 - 12/31/2013	10,000	90.20	(295)
Oil	07/01/2013 - 12/31/2013	10,000	90.65	(269)
Total open oil swap contracts				(564)

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (thousands)
Purity Ethane	07/01/2013 - 12/31/2013	110,000	0.335	57
Purity Ethane	07/01/2013 - 12/31/2013	110,000	0.355	71
Propane	07/01/2013 - 12/31/2013	53,000	0.953	30
Propane	07/01/2013 - 12/31/2013	106,000	0.960	65
Propane	07/01/2013 - 12/31/2013	53,000	1.001	45
Propane	01/01/2014 - 12/31/2014	116,000	0.950	141
Normal Butane	07/01/2013 - 12/31/2013	14,700	1.455	22
Normal Butane	07/01/2013 - 12/31/2013	14,700	1.560	32
Normal Butane	07/01/2013 - 12/31/2013	21,000	1.575	47
Normal Butane	07/01/2013 - 12/31/2013	117,000	1.575	268
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	75
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	211
Isobutane	07/01/2013 - 12/31/2013	7,000	1.515	11
Isobutane	07/01/2013 - 12/31/2013	7,000	1.625	16
Isobutane	07/01/2013 - 12/31/2013	43,500	1.675	110
Isobutane	07/01/2013 - 12/31/2013	23,000	1.675	62
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	114
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	184
Natural Gasoline	07/01/2013 - 12/31/2013	12,000	2.025	4
Natural Gasoline	07/01/2013 - 12/31/2013	12,000	2.085	8
Natural Gasoline	07/01/2013 - 12/31/2013	12,000	2.102	9
Natural Gasoline	07/01/2013 - 12/31/2013	36,000	2.105	29
Natural Gasoline	07/01/2013 - 12/31/2013	90,500	2.148	98
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	32
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	60
Total open NGL swap contracts				1,801
Total open derivative financial instruments				$7,180

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, the Company’s Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2013, to ensure that information required to be disclosed in the reports the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the

50

Table of Contents

Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer, the Company determined that, during the second quarter of 2013, there were no changes in its internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Table of Contents

Part II—OTHER INFORMATION

Item 1. Legal Proceedings

See Part 1, Item 1 – “Financial Statements,” “Note 9 – Commitments and Contingencies” of this Quarterly Report, 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 the Annual Report.

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

On August 7, 2013, Matador, as a guarantor, and MRC Energy Company (“MRC”), as borrower, entered into an amendment (the “Third Amendment”) to the Credit Agreement, pursuant to which Matador reaffirmed its guarantee of MRC’s obligations under the Credit Agreement, as amended. Pursuant to the Third Amendment, the borrowing base under the Credit Agreement was increased from $280.0 million to $350.0 million based on the lenders' review of the Company’s proved oil and natural gas reserves at June 30, 2013. The conforming borrowing base was also increased from $245.0 million to $275.0 million. The Third Amendment also amended the Credit Agreement to provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by the Company of senior unsecured notes in an amount greater than or equal to $10.0 million. For a further description of the Third Amendment, see Part 1, Item 2 – “Management's Discussion and Analysis of Financial Condition and Results of Operations,” “Liquidity and Capital Resources,” “Credit Agreement” of this Quarterly Report. The foregoing summary of the Third Amendment does not purport to be complete and is subject to, and qualified in its entirety by, the full text of the Third Amendment, a copy of which is filed as Exhibit 10.2 to this Quarterly Report and incorporated herein by reference.

In the ordinary course of their respective businesses, certain of the lenders or their affiliates have in the past performed, and may in the future from time to time perform, investment banking, advisory, lending and/or commercial banking or other financial services for the Company for which they received, or may receive, customary fees and reimbursement of expenses.

Item 6. Exhibits

A list of exhibits filed herewith is contained in the Exhibit Index that immediately precedes such exhibits and is incorporated by reference herein.

Table of Contents

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: August 9, 2013	By:	/s/ Joseph Wm. Foran Joseph Wm. Foran Chairman, President and Chief Executive Officer
Date: August 9, 2013	By:	/s/ David E. Lancaster David E. Lancaster Executive Vice President, Chief Operating Officer and Chief Financial Officer

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
10.1	Second Amendment to Third Amended and Restated Credit Agreement, dated as of June 4, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 6, 2013).
10.2	Third Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (filed herewith).
10.3**	First Amendment to Purchase Sale and Participation Agreement, dated as of June 12, 2013, by and between MRC Energy Company and Orca/ICI Development (filed herewith).
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 June 30, 2013, 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 - Unaudited (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.

** Portions of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted portions have been filed separately with the SEC.

54