Mid-Con Energy Partners, LP
Form 10-Q
August 07, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2013

OR

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

Commission File No.: 1-35374

Mid-Con Energy Partners, LP

(Exact name of registrant as specified in its charter)

Delaware	**45-2842469**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

2501 North Harwood Street, Suite 2410

Dallas, Texas 75201

(Address of principal executive offices and zip code)

(972) 479-5980

(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. Yes x 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) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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. (Check one):

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 Act). Yes ¨ No x

As of August 7, 2013, the registrant had 19,296,258 common units and 360,000 general partner units outstanding.

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FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (Form 10-Q) contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (each a forward looking statement). These forward looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategies;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- oil and natural gas reserves;
- technology;
- realized oil and natural gas prices;
- production volumes;
- lease operating expenses;
- general and administrative expenses;
- future operating results;
- cash flow and liquidity;
- availability of production equipment;
- availability of oil field labor;
- capital expenditures;
- availability and terms of capital;

- marketing of oil and natural gas;
- general economic conditions;
- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation;
- developments in oil producing and natural gas producing countries; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 1. Financial Statements, Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and other items within this Form 10-Q. In some

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cases, forward-looking statements can be identified by terminology such as may, will, could, should, expect, plan, project, intend, believe, estimate, predict, potential, pursue, target, continue, goal, forecast, guidance, might, scheduled and the negative comparable terminology.

The forward-looking statements contained in this Form 10-Q are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this Form 10-Q are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the forward-looking events will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the Risk Factors section included in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2012 (Annual Report). This document is available through our web site, www.midconenergypartners.com or through the Securities and Exchange Commission s (SEC) Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. All forward-looking statements speak only as of the date made, and other than as required by law; we do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.midconenergypartners.com) copies of our Annual Reports, Form 10-Qs, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and Ethics, Governance Guidelines, Partnership Agreement and the written charter of our Audit Committee are also available on our website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

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PART I

FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Balance Sheets

(in thousands, except number of units)

(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 811	$ 1,053
Accounts receivable:		
Oil and gas sales	6,777	6,413
Other	200	603
Derivative financial instruments	2,685	3,679
Prepaids and other	555	25
Total current assets	11,028	11,773
PROPERTY AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	209,029	167,036
Accumulated depletion, depreciation and amortization	(29,098)	(21,727)
Total property and equipment, net	179,931	145,309
DERIVATIVE FINANCIAL INSTRUMENTS	1,202	858
OTHER ASSETS	398	650
Total assets	$ 192,559	$ 158,590
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 1,330	$ 2,168
Related parties	3,667	3,036
Accrued liabilities	558	315
Total current liabilities	5,555	5,519
DERIVATIVE FINANCIAL INSTRUMENTS	183	
LONG-TERM DEBT	111,000	78,000
ASSET RETIREMENT OBLIGATIONS	3,863	2,890
EQUITY, per accompanying statements:		
Partnership equity		

General partner interest	1,811	1,814
Limited partners- 19,226,350 and 18,990,849 units issued and outstanding as of June 30, 2013 and December 31, 2012, respectively	70,147	70,367
Total equity	71,958	72,181
Total liabilities and equity	$ 192,559	$ 158,590

See accompanying notes to condensed consolidated financial statements

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Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Operations

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Oil sales	$ 20,926	$ 13,662	$ 40,924	$ 28,998
Natural gas sales	184	182	362	353
Realized gain on derivatives, net	709	903	1,382	769
Unrealized gain (loss) on derivatives, net	960	14,514	(833)	9,741
Total revenues	22,779	29,261	41,835	39,861
Operating costs and expenses:				
Lease operating expenses	3,745	2,778	7,091	4,725
Oil and gas production taxes	873	42	1,663	713
Impairment of proved oil and gas properties	1,578		1,578	
Depreciation, depletion and amortization	3,908	2,397	7,371	4,709
Accretion of discount on asset retirement obligations	39	30	77	57
General and administrative	1,289	1,239	8,037	4,869
Total operating costs and expenses	11,432	6,486	25,817	15,073
Income from operations	11,347	22,775	16,018	24,788
Other income (expense):				
Interest income and other	3	3	4	5
Interest expense	(812)	(350)	(1,425)	(703)
Total other expense	(809)	(347)	(1,421)	(698)
Net income	$ 10,538	$ 22,428	$ 14,597	$ 24,090
Computation of net income per limited partner unit:				
General partners interest in net income	$ 194	$ 444	$ 269	$ 478
Limited partners interest in net income	$ 10,344	$ 21,984	$ 14,328	$ 23,612
Net income per limited partner unit (basic and diluted)	$ 0.54	$ 1.24	$ 0.75	$ 1.33
Weighted average limited partner units outstanding:				
(basic and diluted)	19,230	17,790	19,189	17,764

See accompanying notes to condensed consolidated financial statements

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Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Cash Flows

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash Flows from Operating Activities:		
Net income	$ 14,597	$ 24,090
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	7,371	4,709
Debt placement fee amortization	84	54
Accretion of discount on asset retirement obligations	77	57
Impairment of proved oil and gas properties	1,578	
Unrealized (gain) loss on derivative instruments, net	833	(9,741)
Equity-based compensation	4,768	2,690
Changes in operating assets and liabilities:		
Accounts receivable	(364)	1,020
Other receivables	403	(824)
Prepaids and other	(363)	2,277
Accounts payable and accrued liabilities	599	52
Net cash provided by operating activities	29,583	24,384
Cash Flows from Investing Activities:		
Additions to oil and gas properties	(14,533)	(7,566)
Acquisitions of oil properties	(28,704)	(16,426)
Net cash used in investing activities	(43,237)	(23,992)
Cash Flows from Financing Activities:		
Proceeds from line of credit	66,000	16,000
Payments on line of credit	(33,000)	(3,000)
Distributions paid	(19,588)	(9,656)
Net cash provided by financing activities	13,412	3,344
Net (decrease) increase in cash and cash equivalents	(242)	3,736
Beginning cash and cash equivalents	1,053	228
Ending cash and cash equivalents	$ 811	$ 3,964
Supplemental Cash Flow Information:		
Cash paid for interest	$ 1,339	$ 673
Non-Cash Investing and Financing Activities:		

Accrued capital expenditures - oil and gas properties	$	442	$	932

See accompanying notes to condensed consolidated financial statements

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Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Changes in Equity

(in thousands)

(Unaudited)

	General Partner	Limited Partner Units	Limited Partner Amount	Total Equity
Balance, December 31, 2012	$ 1,814	18,991	$ 70,367	$ 72,181
Equity-based compensation	88	235	4,680	4,768
Distributions	(360)		(19,228)	(19,588)
Net income	269		14,328	14,597
Balance, June 30, 2013	$ 1,811	19,226	$ 70,147	$ 71,958

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Nature of Operations

Mid-Con Energy Partners, LP (we, our, us, the Partnership) is a publicly held limited partnership that engages in the acquisition, development and production of oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. We completed our initial public offering (Initial Public Offering) in December 2011 and our common units are traded on the NASDAQ Global Select Market under the symbol MCEP . Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.

Basis of Presentation

Our unaudited condensed consolidated financial statements included herein have been prepared pursuant to the rules and regulations of the SEC. These financial statements have not been audited by our independent registered public accounting firm, except that the condensed consolidated balance sheet at December 31, 2012 is derived from the audited financial statements. Accordingly, certain information and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted in this Form 10-Q. We believe that the presentations and disclosures herein are adequate to make the information not misleading. The unaudited condensed consolidated financial statements reflect all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the interim periods. The results of operations for the interim periods are not necessarily indicative of the results of operations to be expected for the full year. These interim financial statements should be read in conjunction with our Annual Report for the year ended December 31, 2012.

All intercompany transactions and account balances have been eliminated. In the Notes to Unaudited Condensed Consolidated Financial Statements, all dollar and unit amounts in tabulations are in thousands of dollars and units, respectively, unless otherwise indicated.

The condensed consolidated financial statements for previous periods include certain reclassifications to the accounts payable account that were made to conform to current presentation. Such reclassifications have no impact on previously reported total assets, total liabilities, net income or unitholders capital.

Note 2. Acquisitions

During May 2013, we acquired additional working interests in our Cushing properties located in the Northeastern Oklahoma core area and in certain Southern Oklahoma units. The results of operations of these properties have been included in the unaudited condensed consolidated financial statements since the acquisition date. We paid approximately $28.4 million in aggregate consideration for the interests, subject to customary purchase price adjustments, and the transaction was accounted for under the acquisition method. The transaction was financed using proceeds from our credit facility.

Note 3. Equity Awards

We have a long-term incentive program (the Long-Term Incentive Program) for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, LLC (Mid-Con Energy Operating), who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, restricted units, phantom units, distribution equivalent rights granted with phantom units, and other types of awards and it is administered by the members of our general partner and approved by the Board of Directors of the general partner. The Long-Term Incentive Program permits the grant of awards covering an aggregate of 1,764,000 units under the Form S-8 we filed with the SEC on January 25, 2012. As of June 30, 2013, there were 1,177,650 units available for issuance under the Plan.

In January 2013, we issued 199,500 unrestricted common units (URUs) to employees, officers, directors and consultants of our general partner and affiliates. Also, in January 2013, we issued 40,001 restricted common units (RUs) that have a three- year vesting period. The fair market value of both the URUs and RUs was based on the closing price of our common units at the date of the awards, which was $22.41 per unit. The RUs are subject to forfeiture and we assume a 10% forfeiture rate for the RUs to estimate our equity-based compensation expense.

As of June 30, 2013, there was approximately $1.2 million of unrecognized compensation cost related to nonvested units. The cost is expected to be recognized over a weighted average period of approximately 2.2 years.

The equity-based compensation expense for the three and six months ended June 30, 2013 was $0.1 million and $4.8 million, respectively, and for the three months and six months ended June 30, 2012 was $0.1 million and $2.7 million, respectively. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statements of operations.

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity prices and interest rates and to assist with stabilizing cash flows. Accordingly, we utilize derivative financial instruments to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and the NYMEX futures prices. Our policies do not permit the use of derivatives for speculative purposes.

At June 30, 2013, our open positions consisted of crude oil price collar contracts and crude oil price swap contracts. Under commodity swap agreements, we exchange a stream of payments over time according to specified terms with another counterparty. In a typical commodity swap agreement, we agree to pay an adjustable or floating price tied to an agreed upon index for the oil commodity and in return receive a fixed price based on notional quantities. A collar is a combination of a put purchased by a party and a call option sold by the same party. In a typical collar transaction, if the floating price based on a market index is below the floor price, we receive from the counterparty an amount equal to this difference multiplied by the specified volume. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty an amount equal to the difference multiplied by the specific quantity.

We have elected not to designate any of our positions as cash flow hedges for accounting purposes and, accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in our unaudited condensed consolidated statements of operations. Pursuant to the accounting standard that permits netting of assets and liabilities where the right of offset exists, we present the fair value of derivative financial instruments on a net basis.

As of June 30, 2013, we had the following oil derivative open positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day
Swaps - 2013	$ 98.08			1,696
Collars - 2013		$ 97.67	$ 108.08	293
Swaps - 2014	$ 93.56			1,973
Swaps - 2015	$ 90.05			164

Our oil derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, it is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. We evaluate the credit standing of such counterparties by reviewing their credit rating. The counterparties to our derivative contracts currently in place are lenders under our credit facility and have investment grade ratings.

The following table summarizes the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in our condensed consolidated balance sheets at June 30, 2013 (in thousands):

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	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
As of June 30, 2013:			
Assets			
Derivative financial instrument - current asset	$ 2,761	$ 75	$ 2,686
Derivative financial instrument - long-term asset	1,277	76	1,201
Total	$ 4,038	$ 151	$ 3,887
Liabilities			
Derivative financial instrument - current liability	$ (75)	$ (75)	$
Derivative financial instrument - long-term liability	(259)	(76)	(183)
Total	$ (334)	$ (151)	$ (183)
Net assets	$ 3,704	$	$ 3,704

The following table presents the impact of derivative financial instruments and their location within the unaudited condensed consolidated statements of operations (in thousands):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Realized gain on derivatives, net	$ 709	$ 903	$ 1,382	$ 769
Unrealized gain (loss) on derivatives, net	960	14,514	(833)	9,741
Total gain on derivatives, net	$ 1,669	$ 15,417	$ 549	$ 10,510

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our balance sheet for cash, accounts receivable, accounts payable and derivative financial instruments approximate their fair values. The carrying amount of long-term debt under our credit facility approximates fair value because the credit facility s variable interest rate resets frequently and approximates current market rates available to us.

We account for our oil and gas commodity derivatives at fair value. The fair value of our derivative financial instruments is determined utilizing NYMEX closing prices for the contract period.

Fair Value Measurements

Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a three-tier fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Our assets and liabilities recorded in the balance sheet are categorized based on the inputs to the valuation technique as follows:

Level 1 Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access.

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Level 2 Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

Level 3 Financial assets and liabilities for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management s own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We account for our commodity derivatives at fair value on a recurring basis. We use certain pricing models to determine the fair value of our derivative financial instruments. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. See Note 4 for a summary of our derivative financial instruments.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

We estimate the fair value of the asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note 6 for a summary of changes in asset retirement obligations.

We review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds its estimated fair value. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. During the three and six months ended June 30, 2013, we recorded a non-cash impairment charge of $1.6 million within our miscellaneous core area, due to a decline in reserve estimates. The charge is included in impairment of proved oil and gas properties in our unaudited condensed consolidated statements of operations. There was no impairment charge for both the three and six months ended June 30, 2012.

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The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value as of June 30, 2013 and December 31, 2012 (in thousands):

	Level 1	Level 2 (in thousands)	Level 3
June 30, 2013			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	$	$ 3,887	$
Derivative financial instruments- liability	$	$ 183	$
Net financial assets	$	$ 3,704	$
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$	$	$ 896
Impairment of proved oil and gas properties	$	$	$ 1,578
December 31, 2012			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	$	$ 4,537	$
Derivative financial instruments- liability	$	$	$
Net financial assets	$	$ 4,537	$
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$	$	$ 845
Impairment of proved oil and gas properties	$	$	$ 1,296

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation techniques or related inputs for the six months ended June 30, 2013.

Note 6. Asset Retirement Obligations

Asset retirement obligations (ARO) are recorded as a liability at their estimated present value at the various assets inception, with the offsetting charge to oil and gas properties. Periodic accretion of the discounted estimated liability is recorded in the condensed consolidated statement of operations. The discounted capitalized cost is amortized to expense through the depreciation calculation over the life of the assets based on proved developed reserves.

Our AROs represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their production lives, in accordance with applicable state laws. We determine our ARO by calculating the present value of estimated cash flow related to the liability. Each year we review and, to the extent necessary, revise our ARO estimates.

Changes in our ARO for the periods indicated are presented in the following table:

	Six Months Ended June 30, 2013	Year Ended December 31, 2012
	(in thousands)	
Asset retirement obligation - beginning of period	$ 2,890	$ 1,919
Liabilities incurred for new wells and interests	964	636
Revision of estimates	(68)	209
Accretion expense	77	126
Asset retirement obligation - end of period	$ 3,863	$ 2,890

As of June 30, 2013 and December 31, 2012, $3.9 million and $2.9 million, respectively, of our ARO was classified as long-term and was reported as Asset Retirement Obligations in our unaudited condensed consolidated balance sheets.

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Note 7. Debt

As of June 30, 2013, our credit facility consists of a $250.0 million senior secured revolving facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders. At June 30, 2013, we had approximately $111.0 million of borrowings outstanding under the revolving credit facility. The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a current ratio of no less than 1.0 to 1.0.

The credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and payments. If we fail to perform our obligations under these and other covenants, the revolving credit commitments may be terminated and any outstanding indebtedness under the credit agreement, together with accrued interest could be declared immediately due and payable. As of June 30, 2013, we were in compliance with all debt covenants.

During the 2012 borrowing base determinations, our borrowing base under the credit facility was increased from $75.0 million to $100.0 million and from $100.0 million to $130.0 million, in April and November, respectively. On April 9, 2013, the borrowing base under the credit facility was reaffirmed at $130.0 million. No material terms of the agreement were amended. Borrowings under the facility may not exceed our current borrowing base of $130.0 million. The borrowing base is determined by the lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations on or about April 30 and October 31 of each year with an additional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract.

Borrowings under the credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of the Royal Bank of Canada, the federal funds effective rate plus 0.50%, or the one month adjusted London Interbank Offered Rate (LIBOR) plus 1.0%, all of which are subject to a margin that varies from 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. For the three months ended June 30, 2013, the average effective interest rate was approximately 2.78%. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

On May 9, 2013, we borrowed an additional $28.4 million from our credit facility to acquire additional interests in our Southern Oklahoma and Northeastern Oklahoma core areas as explained in Note 2 of these financial statements.

Note 8. Commitment and Contingencies

We have a service agreement with Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating will provide certain services to us, our subsidiaries and our general partner, including management, administrative and operations services, which include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for or on our behalf and other expenses allocated by Mid-Con Energy Operating to us.

We are party to various claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, the ultimate resolution of all claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our financial position, results of operations or cash flows.

Our general partner has entered into employment agreements with certain executive officers. The employment agreements provide for a term that commenced on August 1, 2011 and expires on August 1, 2014, unless earlier terminated, with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities, and authority as the board of directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him. The agreement stipulates that if there is a change of control, termination of employment with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $1.6 million to $1.9 million, including the value of vesting of any outstanding units.

Note 9. Equity

Common Units

On October 22, 2012, we and Yorktown sold 4,600,000 common units to the public at a price of $21.20 per common unit. 1,000,000 common units were sold by us, and 3,600,000 common units were sold by Yorktown Energy Partners, VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P (collectively Yorktown). Proceeds from our 1,000,000 common units offering, net of underwriting discounts and expenses, were approximately $20.4 million. We did not receive any proceeds from the 3,600,000 common units sold by Yorktown.

In January 2013, we issued 7,994 common units related to the vesting of restricted units that were granted in 2012 and vested in January 2013.

At June 30, 2013 and December 31, 2012, Partnership s equity consisted of 19,226,350 and 18,990,849 common units, respectively, representing approximately a 98% limited partnership interest in us.

Cash Distributions

The following sets forth the distributions we paid during the six months ended June 30, 2013 (in thousands):

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 14, 2013	October 1, 2012 - December 31, 2012	$ 0.495	$ 9,697
May 14, 2013	January 1, 2013 - March 31, 2013	$ 0.505	$ 9,891
			$ 19,588

On July 24, 2013, the Board of Directors of our general partner declared a quarterly cash distribution for the second quarter of 2013 of $0.515 per unit, or $2.06 on an annualized basis, an increase of $0.01 from the previous quarter, which will be paid on August 14, 2013 to unitholders of record at the close of business on August 7, 2013. The aggregate amount of the distribution will be approximately $10.1 million.

Allocation of Net Income (Loss)

Net income (loss) is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership during the period.

Note 10. Related Party Transactions

The following agreements were negotiated among affiliated parties and, consequently, are not the result of arm s length negotiations. The following is a description of those agreements that have been entered into with the affiliates of our general partner and with our general partner. We, our general partner and its affiliates have entered into the various documents and agreements, which are described below.

Services Agreement

We are party to a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides certain services to us, including management, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. During the three and six months ended June 30, 2013, we reimbursed Mid-Con Energy Operating approximately $0.6 million and $1.8 million, for direct expenses, respectively. These costs are included in the general and administrative expenses in our unaudited condensed consolidated statements of operations.

Other Transactions with Related Persons

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies, or COPAS fees). These costs are included in lease operating expenses in our unaudited condensed consolidated statements of operations.

At June 30, 2013, we had a payable to Mid-Con Energy Operating of approximately $3.7 million which was comprised of a joint interest billing payable of approximately $3.5 million and a payable for operating services of approximately $0.2 million. These amounts are included in the accounts payable for related parties in our unaudited condensed consolidated balance sheets. At December 31, 2012 we had a payable to Mid-Con Energy Operating of approximately $3.0 million which was comprised of a joint interest billing payable of approximately $2.7 million and a payable for operating services of approximately $0.3 million. These amounts are included in the accounts payable in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2011-11, *Disclosures about Offsetting Assets and Liabilities*, which requires disclosure of both gross information and net information about derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to master netting arrangements. This information will enable users on an entity s financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of set-off associated with certain financial instruments and derivative instruments within the scope of the update. We adopted this guidance on January 1, 2013, and the adoption of this ASU did not have an effect on our condensed consolidated financial statements.

Note 12. Subsequent Events

On July 24, 2013, the Board of Directors of our general partner declared a quarterly cash distribution for the second quarter of 2013 of $0.515 per unit, or $2.06 on an annualized basis, an increase of $0.01 from the previous quarter, which will be paid on August 14, 2013 to unitholders of record at the close of business on August 7, 2013. The aggregate amount of the distribution will be approximately $10.1 million.

Also, on July 24, 2013, the Board of Directors of our general partner authorized the issuance 69,908 common units and 50,000 phantom units to certain employees of our affiliates and certain directors and founders of our general partner.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our unaudited condensed consolidated financial statements and the related notes thereto, as well as our Annual Report.

Overview

We are a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our common units are traded on the NASDAQ Global Select Market under the symbol MCEP .

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On October 22, 2012, we and Yorktown sold an aggregate of 4,600,000 common units to the public at a price of $21.20 per common unit. 1,000,000 common units were sold by us, and 3,600,000 common units were sold by Yorktown. We used the net proceeds of approximately $20.4 million from the sale of our 1,000,000 common units, after deducting underwriting discounts but before offering expenses, to repay borrowings outstanding under our credit facility. We did not receive any proceeds from the 3,600,000 common units sold by Yorktown.

Our properties are located in the Mid-Continent region of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

We have grown our reserves and production substantially since our initial public offering in December 2011. With the acquisitions in 2012 of additional interests in the War Party Units and the acquisition of the Clawson Ranch Waterflood Unit we have been able to increase our reserves and production in the Hugoton area. Our drilling activity in our Southern Oklahoma core area and acquisitions of additional interest have also increased our reserve base and our production. With the recent unitization of the Cleveland Field Unit and the recent acquisition of additional interests in our Cushing properties, the Northeastern Oklahoma core areas reserve base and daily production have also increased. We will continue to develop these areas with capital development programs through drilling and completion activities.

We are an emerging growth company as defined in Section 101 of the Jumpstart Our Business Startups Act of 2012, or the JOBS Act.

Quarterly Highlights

On April 9, 2013, the borrowing base under the credit facility was reaffirmed at $130.0 million.

On April 22, 2013, the Board of Directors of our general partner and the General Partner (Mid-Con Energy GP, LLC):

- Increased the size of the board of directors to nine members.
- Elected Dr. Michael L. Wiggins as a director and Mr. C. Fred Ball, Jr. as an independent director of the General Partner. Mr. Ball was also appointed to the audit committee.

On May 14, 2013, we paid a cash distribution to unitholders for the first quarter of 2013 at the rate of $0.505 per unit. The aggregate distribution was approximately $9.9 million.

During May 2013, we acquired additional working interests in our Cushing properties located in the Northeastern Oklahoma and in certain Southern Oklahoma units for approximately $28.4 million, subject to customary purchase price adjustments.

Business Environment

The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future, which means that the price of oil can fluctuate widely. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil reserves that we can economically produce and our access to capital.

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program s objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distributions over time, while retaining some ability to participate in upward moves in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher amount of hedged volumes in the near 12 months.

Our business faces the challenge of natural production declines. As initial reservoir pressures are depleted, oil production from a given well or formation decreases. Although our waterflood operations tend to restore reservoir pressure and production, once a waterflood is fully effected, production, once again, begins to decline. Our future growth will depend on our ability to continue to add reserves in excess of our production. We plan to maintain our focus on adding reserves primarily through improving the economics of producing oil from our existing fields and, secondarily, through acquisitions and development of additional proved reserves. Our ability to add reserves through exploitation projects and acquisitions is dependent upon many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel, and successfully identify and close acquisitions.

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We 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 future cash flows from operations are impacted by our ability to manage our overall cost structure.

How We Evaluate Our Operations

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which will provide stability and, over time, growth of distributions to our unitholders. The amount of cash that we can distribute to our unitholders depends principally on the cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other factors:

- the amount of oil and natural gas we produce;
- the prices at which we sell our oil and natural gas production;
- our ability to hedge commodity prices; and
- the level of our operating and administrative costs.

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Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Oil sales	$ 20,926	$ 13,662	$ 40,924	$ 28,998
Natural gas sales	184	182	362	353
Realized gain on derivatives, net	709	903	1,382	769
Unrealized gain (loss) on derivatives, net	960	14,514	(833)	9,741
Total revenues	$ 22,779	$ 29,261	$ 41,835	$ 39,861
Operating costs and expenses:				
Lease operating expenses	$ 3,745	$ 2,778	$ 7,091	$ 4,725
Oil and gas production taxes	$ 873	$ 42	$ 1,663	$ 713
Impairment of proved oil and gas properties	$ 1,578	$	$ 1,578	$
Depreciation, depletion and amortization	$ 3,908	$ 2,397	$ 7,371	$ 4,709
General and administrative (1)	$ 1,289	$ 1,239	$ 8,037	$ 4,869
Interest expense	$ 812	$ 350	$ 1,425	$ 703
Production:				
Oil (MBbls)	230	154	450	304
Natural gas (MMcf)	36	28	73	60
Total (MBoe)	236	159	462	314
Average net production (Boe/d)	2,593	1,747	2,552	1,725
Average sales price:				
Oil (per Bbl):				
Sales price	$ 90.98	$ 88.71	$ 90.94	$ 95.39
Effect of realized commodity derivative instruments	$ 3.08	$ 5.86	$ 3.07	$ 2.53
Realized price	$ 94.06	$ 94.57	$ 94.01	$ 97.92
Natural gas (per Mcf):				
Sales price (2)	$ 5.11	$ 6.50	$ 4.96	$ 5.88
Average unit costs per Boe:				
Lease operating expenses	$ 15.87	$ 17.47	$ 15.35	$ 15.05
Oil and gas production taxes	$ 3.70	$ 0.26	$ 3.60	$ 2.27
Depreciation, depletion and amortization	$ 16.56	$ 15.08	$ 15.95	$ 15.00
General and administrative expenses	$ 5.46	$ 7.79	$ 17.40	$ 15.51

(1) General and administrative expenses include non-cash, equity-based compensation of $0.1 million and $4.8 million for the three and six months ended June 30, 2013; and $0.1 million and $2.7 million for the three and six months ended June 30, 2012, respectively.

(2) Natural gas sales price per Mcf includes the sale of natural gas liquids.

Three Months Ended June 30, 2013 Compared with the Three Months Ended June 30, 2012.

Net income was approximately $10.5 million for the three months ended June 30, 2013, compared to approximately $22.4 million net income for the three months ended June 30, 2012, a decrease of approximately $11.9 million. The decrease was primarily attributable to changes in the mark-to-market fair value of our non-cash derivative contracts, higher impairment costs of our oil and natural gas properties, increased depreciation, depletion and amortization expense, and higher operating costs, partially offset by an increase in oil sales during the three months ended June 30, 2013.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended June 30, 2013, were approximately $21.1 million compared to approximately $13.8 million for the three months ended June 30, 2012. The increase in revenues was primarily due to an increase in the volume of daily oil production from our successful drilling efforts and incremental volumes from recent acquisitions.

Our production volumes for the three months ended June 30, 2013, were approximately 236 MBoe, or approximately 2,593 Boe per day on average. In comparison, our total production volumes for the three months ended June 30, 2012, were approximately 159 MBoe, or approximately 1,747 Boe per day on average. The increase in production volumes was primarily the result of ongoing waterflood response to injection, increased infill drilling in our Southern Oklahoma core area as well as from wells drilled as part of drilling program in the Hugoton Basin core area and from acquisitions in 2012. Further, the recent acquisition of additional working interest in our existing Cushing properties favorably impacted our oil and natural gas production in the second quarter of 2013. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended June 30, 2013, was approximately $90.98, compared with approximately $88.71 for the three months ended June 30, 2012.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. Due to the period change in the mark-to-market value of these contracts, we recorded a lower net gain from our commodity hedging instruments for the three months ended June 30, 2013, when compared to the same period in 2012. Net gain for three months ended June 30, 2013 was approximately $1.7 million, which was composed of an unrealized gain of approximately $1.0 million and a realized gain of approximately $0.7 million. Correspondingly, for the three months ended June 30, 2012, we recorded a net gain from our commodity hedging program of approximately $15.4 million, which was composed of a $14.5 million unrealized gain and a realized gain of approximately $0.9 million.

Lease Operating Expenses. Our lease operating expenses were approximately $3.7 million for the three months ended June 30, 2013, or approximately $15.87 per Boe, compared to approximately $2.8 million for the three months ended June 30, 2012, or approximately $17.47 per Boe. The increase in total lease operating expenses over the prior year s quarter was primarily attributable to the additional number of producing wells resulting from our drilling programs and the additional oil properties and working interests acquired in the later part of 2012 and in May 2013. The decrease in lease operating expenses per Boe was primarily due to additional production for the three months ended June 30, 2013.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. Our production taxes were approximately $0.9 million for the three months ended June 30, 2013, or approximately $3.70 per Boe for an effective tax rate of approximately 4.1%, compared to approximately $42,000 for the three months ended June 30, 2012, or approximately $0.26 per Boe for an effective tax rate of approximately 0.3%. The increase in production taxes during the three months ended June 30, 2013, was directly related to higher oil and gas revenues driven by increased production. The decrease in production taxes per Boe during the three months ended June 30, 2012 was primarily due to receiving approximately $0.5 million of prior period production tax adjustments for one of our Southern Oklahoma units. The adjustment was due to the Enhanced Recovery Project Gross Production Tax Exemption.

Although the State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%, a portion of our wells in Oklahoma currently receive a reduced tax rate due to the Enhanced Recovery Project Gross Production Tax Exemption.

Impairment Expense. Our impairment expense was approximately $1.6 million for the three months ended June 30, 2013. We review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If the carrying amount exceeds the property s estimated fair value, we adjust the carrying amount of the property to fair value through a charge to impairment expense. We recorded approximately a $1.6 million non-cash impairment charge within our miscellaneous core area wells. There was no impairment charge for the three months ended June 30, 2012.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses (DD&A) on producing properties for the three months ended June 30, 2013, were approximately $3.9 million, or approximately $16.56 per Boe produced, compared to approximately $2.4 million, or approximately $15.08 per Boe produced, for the three months ended June 30, 2012. The increase in depreciation, depletion and amortization expenses was primarily due to an increase in total asset value of the oil and gas properties from our drilling program, the acquisition of properties and additional working interests in our Hugoton Basin, Southern and Northeastern Oklahoma core areas during 2012 and 2013. The increase in the DD&A rate is due to the acquisition of additional working interest in existing Southern Oklahoma properties during the later half of 2012 and the recent working interest acquisition in existing Northeastern Oklahoma properties, each having higher DD&A rates.

General and Administrative Expenses. Our general and administrative expenses were approximately $1.3 million for the three months ended June 30, 2013, or approximately $5.46 per Boe produced, compared to approximately $1.2 million for the three months ended June 30, 2012, or approximately $7.79 per Boe produced. The slight increase in general and administrative expenses for the three months ended June 30, 2013 primarily reflects miscellaneous costs including the hiring of additional staff. During both the three months ended June 30, 2013 and 2012, general and administrative costs included non-cash equity-based compensation of $0.1 million.

Interest Expense. Our interest expense for the three months ended June 30, 2013, was approximately $0.8 million, compared to $0.4 million for the three months ended June 30, 2012. The increase was due to higher borrowings outstanding from our credit facility during the three months ended June 30, 2013 compared to the three months ended June 30, 2012.

Six Months Ended June 30, 2013 Compared with the Six Months Ended June 30, 2012.

Net income was approximately $14.6 million for the six months ended June 30, 2013 compared to approximately $24.1 million for the six months ended June 30, 2012, a decrease of approximately $9.5 million. This decrease primarily reflects the impact of changes in the mark-to-market fair value of our non-cash derivative contracts, higher general and administrative expenses (including equity-based compensation expense), higher depreciation, depletion and amortization expense along with increased operating expenses, partially offset by an increase in oil sales during the six months ended June 30, 2013, which reflects our continued growth.

Sales Revenues. Revenues from oil and natural gas sales for the six months ended June 30, 2013 were approximately $41.3 million as compared to approximately $29.4 million for the six months ended June 30, 2012. The increase in revenues was primarily due to an increase in daily oil production which includes incremental volumes from recent acquisitions of both properties and working interests.

Our production volumes for the six months ended June 30, 2013 were approximately 462 MBoe, or approximately 2,552 Boe per day. In comparison, our total production volumes for the six months ended June 30, 2012, were approximately 314 MBoe, or approximately 1,725 Boe per day. The increase in production volumes was primarily due to ongoing waterflood response from injection and our drilling programs in the Southern Oklahoma and Hugoton Basin core areas. Also, the increase in production for the six months ended June 30, 2013 reflects the favorable impact from various acquisitions of oil properties and additional working interests during 2012 and 2013. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the six months ended June 30, 2013 was $90.94, compared with $95.39 for the six months ended June 30, 2012.

In the first quarter ended March 31, 2013, we drilled a total of 8 wells with 7 being producers and 1 being an injector. Additionally, in the second quarter ended June 30, 2013, we drilled a total of 7 wells with 3 being producers and 4 being injectors. Of the 15 total wells drilled during the first half of 2013, 9 wells were awaiting final completion due to timing of injection permits, electricity and equipment.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. Due to the period change in the mark-to-market value of these contracts, we recorded a net gain from our commodity hedging program for the six months ended June 30, 2013, of approximately $0.6 million, which was composed of a realized gain of approximately $1.4 million and an unrealized loss of approximately $0.8 million. For the six months ended June 30, 2012, we recorded a net gain from our commodity hedging program of approximately $10.5 million, which was composed of an unrealized gain of $9.7 million and a realized gain of approximately $0.8 million.

Lease Operating Expenses. Our lease operating expenses were approximately $7.1 million for the six months ended June 30, 2013, or $15.35 per Boe, compared to approximately $4.7 million for the six months ended June 30, 2012, or approximately $15.05 per Boe. The increase in total lease operating expenses and average costs per Boe was primarily attributable to the increased production resulting from the additional number of producing wells due to our drilling program and the additional oil properties and working interest acquired during 2012 and 2013.

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Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. Our production taxes were approximately $1.7 million for the six months ended June 30, 2013, or approximately $3.60 per Boe for an effective tax rate of approximately 4.0%, compared to approximately $0.7 million for the six months ended June 30, 2012, or approximately $2.27 per Boe for an effective tax rate of approximately 2.4%. The increase in production taxes during the six months ended June 30, 2013 was directly related to higher oil and gas revenues driven by increased production. The decrease in the production taxes per Boe during the six months ended June 30, 2012 was primarily due to receiving approximately $0.5 million of prior period production tax adjustment for one of our Southern Oklahoma units. The adjustment was due to the Enhanced Recovery Project Gross Production Tax Exemption.

Although the State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%, a portion of our wells in Oklahoma currently receive a reduced tax rate due to the Enhanced Recovery Project Gross Production Tax Exemption.

Impairment Expense. Our impairment expense was approximately $1.6 million for the six months ended June 30, 2013. We review our long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If the carrying amount exceeds the property s estimated fair value, we adjust the carrying amount of the property to fair value through a charge to impairment expense. We recorded approximately a $1.6 million non-cash impairment charge within our miscellaneous core area properties. There was no impairment charge for the six months ended June 30, 2012.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the six months ended June 30, 2013 were approximately $7.4 million, or approximately $15.95 per Boe produced, compared to approximately $4.7 million, or approximately $15.00 per Boe produced, for the six months ended June 30, 2012. The increase in depreciation, depletion and amortization expenses was primarily due to the increase in total asset value of the oil and gas properties from our drilling program, the acquisitions of properties and additional working interests in our Hugoton Basin, Southern and Northeastern Oklahoma core areas during 2012 and 2013. The increase in the DD&A rate from June 30, 2012 to June 30, 2013 is due to the acquisition of additional working interest in existing Southern Oklahoma properties during the later half of 2012 and the recent working interest acquisition in existing Northeastern Oklahoma properties, each having higher DD&A rates.

General and Administrative Expenses. Our general and administrative expenses were approximately $8.0 million for the six months ended June 30, 2013, or approximately $17.40 per Boe produced compared to approximately $4.9 million for the six months ended June 30, 2012, or approximately $15.51 per Boe produced. The increase in general and administrative expenses for the six months ended June 30, 2013 was primarily due to higher compensation costs, higher professional fees necessary to comply with public reporting requirements, and costs related to the hiring of additional staff. Compensation costs include non- cash equity-based compensation of $4.8 million and $2.7 million for the six months ended June 30, 2013 and 2012, respectively.

Interest Expense. Our interest expense for the six months ended June 30, 2013 was approximately $1.4 million, compared to approximately $0.7 million for the six months ended June 30, 2012. The increase was due to higher borrowings outstanding from our credit facility during the six months ended June 30, 2013 compared to the six months ended June 30, 2012.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

We believe a strong balance sheet is a necessary pre-requisite for creating sustainable growth in unitholder value. Our liquidity position as of June 30, 2013, consisted of approximately $0.8 million of available cash, and $19.0 million of available borrowings under our credit facility. Our primary use of capital has been for the acquisition and development of oil and natural gas properties. As we pursue profitable reserves and production growth, we continually monitor our liquidity and the credit markets. Additionally, we continue to monitor events and circumstances surrounding each of the lenders in our credit facility.

As of June 30, 2013, our $250.0 million credit facility had a remaining borrowing capacity of $19.0 million ($130.0 million borrowing base less $111.0 million of outstanding borrowings). The borrowing is re-determined on or about April 30 and October 31 of each year, beginning with April 30, 2012. In April and November 2012 the borrowing base of our credit facility was increased to $100.0 million and $130.0 million, respectively. On April 9, 2013, the borrowing base under the credit facility was reaffirmed at $130.0 million. No material terms of the agreement were amended.

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Cash Flow

Cash flow provided by (used in) each type of activity was as follows (in thousands):

	Six Months Ended June 30,	
	2013	**2012**
Operating activities	$ 29,583	$ 24,384
Investing activities	(43,237)	(23,992)
Financing activities	13,412	3,344

Operating Activities. Net cash provided by operating activities was approximately $29.6 million and $24.4 million for the six months ended June 30, 2013 and 2012, respectively. The $5.2 million increase from 2012 to 2013 was primarily attributable to higher oil and natural gas revenues resulting from increased production, partially offset by higher cash operating expenses. Our net cash provided by operating activities also includes a reduction of $2.3 million associated with changes in working capital items from 2012 to 2013. Changes in working capital items adjust for the timing of receipts and payments of actual cash. Cash provided by operating activities is impacted by the prices we receive for oil and natural gas sales and production volumes. Our production volumes in the future will in large part be dependent upon the results of past waterflood development activities and results of future capital expenditures.

Investing Activities. Net cash used in investing activities was approximately $43.2 million and approximately $24.0 million for the six months ended June 30, 2013 and 2012, respectively. During the six months ended June 30, 2013 and 2012, we spent $14.5 million and $7.6 million, respectively, on capital expenditures, primarily for drilling and completion activities. During the six months ended June 30, 2013 we paid $28.4 million for the additional working interests in the Cushing properties and certain Southern Oklahoma properties. During the six months ended June 30, 2012 we paid $16.4 million for certain oil properties in Northeastern Oklahoma and additional working interests in our existing units in Southern Oklahoma.

Financing Activities. Our cash flows from financing activities consisted primarily of proceeds from and payments on our credit facility, and distributions to unitholders. Net cash provided by financing activities was approximately $13.4 million and approximately $3.3 million for the six months ended June 30, 2013 and 2012, respectively. During the six months ended June 30, 2013, we received net proceeds of approximately $33.0 million from borrowings under our credit facility which were used to finance the acquisition of additional working interests in our Northeastern Oklahoma and Southern Oklahoma core areas and to develop capital projects. Conversely, we made cash distributions to our unitholders of approximately $19.6 million. During the six months ended June 30, 2012, we received net proceeds of $13.0 million from borrowings under our credit facility and we paid cash distributions of $9.7 million.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size of our asset base. The primary purpose of growth capital is to acquire, develop and produce assets that allow us to increase our production levels and asset base. To date, we have funded acquisition transactions through a combination of cash and available borrowing capacity under our current credit facility. We expect to finance any significant acquisition of oil and natural gas properties in 2013 through the issuance of equity, debt financing or borrowings under our credit facility. Additionally, we currently expect capital spending for the remainder of 2013 for the development, growth and maintenance of our oil and natural gas properties to be approximately $13.2 million.

Credit Facility

We have a $250.0 million senior secured revolving credit facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders. At June 30, 2013, we had approximately $111.0 million of borrowings outstanding under the revolving credit facility. The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0. As of June 30, 2013, we were in compliance with all of the facility s financial covenants.

During 2012, our borrowing base under the credit facility was increased from $75.0 million to $100.0 million and from $100.0 million to $130.0 million, in April and November, respectively. On April 9, 2013, the borrowing base under the credit facility was reaffirmed at $130.0 million. No material terms of the agreement were amended. Borrowings under the facility may not exceed our current borrowing base of $130.0 million. The borrowing base is determined by the lenders based on our oil and natural gas reserves.

For additional information about our long-term debt, such as interest rates and covenants, please see Item 1. Financial Statements contained herein.

Derivative Contracts

At June 30, 2013, our open commodity derivative contracts were in a net asset position with a fair value of approximately $3.7 million. All of our commodity derivative contracts are with major financial institutions. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments in the event of lower commodity prices and we could incur a loss. As of June 30, 2013, all of our counterparties had performed pursuant to their commodity derivative contracts.

All of our derivative contracts for 2013, 2014 and 2015 are either swaps with fixed settlements or collars. These instruments limit our exposure to declines in prices, but also limit the benefits if prices increase. We do not specifically designate commodity derivative contracts as cash flow hedges; therefore, the mark-to-market adjustment reflecting the change in the unrealized gains or losses on these contracts is recorded in current period earnings. When prices for oil are volatile, a significant portion of the effect of our hedging activities consists of non-cash income or expenses due to changes in the fair value of our commodity derivative contracts. Realized gains or losses only arise from payments made or received on monthly settlements or if a commodity derivative contract is terminated prior to its expiration.

See Note 4 to the unaudited condensed consolidated financial statements within this report for a discussion of our derivative contracts.

Off Balance Sheet Arrangements

As of June 30, 2013, we had no off balance sheet arrangements.

Recently Issued Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2011-11, *Disclosures about Offsetting Assets and Liabilities*, which requires disclosure of both gross information and net information about derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to master netting arrangements. This information will enable users on an entity s financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of set-off associated with certain financial instruments and derivative instruments within the scope of the update. We adopted this guidance on January 1, 2013, and the adoption of this ASU did not have an effect on our condensed consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business.

The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

The following should be read in conjunction with the financial statements and related notes included elsewhere in this Form 10-Q and in our Annual Report.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil production. Realized pricing is primarily driven by the spot market prices applicable to the prevailing price for oil. Pricing for oil has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into commodity derivative contracts with respect to a significant portion of our projected oil production through various transactions that fix the future prices received. These hedging activities are intended to manage our exposure to oil price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

Our oil derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, it is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. We evaluate the credit standing of such counterparties by reviewing their credit ratings. The counterparties to our derivative contracts currently in place are lenders under our credit facility and have investment grade ratings. We expect to enter into future derivative contracts with these or other lenders under our credit facility whom we expect will also carry investment grade ratings.

The fair value of our oil commodity contracts and swaps at June 30, 2013, was a net asset of approximately $3.7 million. A 10% change in oil prices with all other factors held constant would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity contracts and swaps of approximately $9.8 million. Please see Item 1. Financial Statements contained herein for additional information.

Interest Rate Risk

At June 30, 2013, we had long-term debt outstanding of $111.0 million, with an effective interest rate of approximately 2.65%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate would be approximately $0.3 million on an annual basis. Our revolving credit facility allows borrowings up to $130.0 million at an interest rate ranging from LIBOR plus 1.75% to LIBOR plus 2.75% or the prime rate plus 0.75% to the prime rate plus 1.75%, depending on the amount borrowed. The prime rate will be the United States prime rate as announced from time-to-time by the Royal Bank of Canada. Please see Item 1. Financial Statements contained herein for additional information.

Counterparty and Customer Credit Risk

We were subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current 2013 production. The inability or failure of any of our customers to meet its obligations to us or its insolvency or liquidation may adversely affect our financial results. However, our current purchasers have positive payment histories.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our chief executive officer (principal executive officer) and chief financial officer (principal financial officer), the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2013. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we filed under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Form 10-Q.

Changes in Internal Controls Over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the quarterly period ended June 30, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In the course of our ongoing preparations for making management s report on internal control over financial reporting as required by Section 404 of the Sarbanes-Oxley Act of 2002, from time to time we have identified areas in need of improvement and have taken remedial actions to strengthen the affected controls as appropriate. We make these and other changes to enhance the effectiveness of our internal control over financial reporting, which do not have a material effect on our overall internal control over financial reporting.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

ITEM 1A. RISK FACTORS

There have been no material changes with respect to the risk factors disclosed in our Annual Report for the year ended December 31, 2012.

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

None.

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ITEM 6. EXHIBITS

The exhibits listed below are filed or furnished as part of this Quarterly Report:

Exhibit No.	Exhibit Description
10.1	Agreement and Amendment No.2 to Credit Agreement, dated as of November 26, 2012, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on November 28, 2012).
31.1+	Rule 13a-14(a)/ 15(d)- 14(a) Certification of Chief Executive Officer
31.2+	Rule 13a-14(a)/ 15(d)- 14(a) Certification of Chief Financial Officer
32.1+	Section 1350 Certificate of Chief Executive Officer
32.2+	Section 1350 Certificate of Chief Financial Officer
101.INS++	XBRL Instance Document
101.SCH++	XBRL Taxonomy Extension Schema Document
101.CAL++	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF++	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB++	XBRL Taxonomy Extension Label Linkbase Document
101.PRE++	XBRL Taxonomy Extension Presentation Linkbase Document

+ Filed herewith

++ In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this 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. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURE

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.

MID-CON ENERGY PARTNERS, LP

By: Mid-Con Energy GP, LLC, its general partner

Date: August 7, 2013

By: */s/ Jeffrey R. Olmstead*
Jeffrey R. Olmstead
President and Chief Financial Officer

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