Mid-Con Energy Partners, LP
Form 10-Q
August 05, 2014

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, 2014
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	o (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 4, 2014, the registrant had 21,128,516 limited partner 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 cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," "goal," "forecast," "might," "scheduled" and the negative of such terms or other 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, 2013 ("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.

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, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,840	$1,434
Accounts receivable:		
Oil and natural gas sales	8,203	6,778
Other	75	104
Derivative financial instruments	—	153
Prepaids and other	392	191
Total current assets	10,510	8,660
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, successful efforts method:		
Proved properties	281,926	216,680
Accumulated depletion, depreciation and amortization	(44,483)	(36,148)
Total property and equipment, net	237,443	180,532
DERIVATIVE FINANCIAL INSTRUMENTS	—	48
OTHER ASSETS	841	843
Total assets	$248,794	$190,083
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$2,991	$2,184
Related parties	5,497	2,982
Derivative financial instruments	5,372	1,627
Accrued liabilities	369	432
Total current liabilities	14,229	7,225
OTHER LONG-TERM LIABILITIES	115	128
LONG-TERM DEBT	139,000	112,000
ASSET RETIREMENT OBLIGATIONS	4,770	3,942
COMMITMENTS AND CONTINGENCIES		
EQUITY, per accompanying statements:		
Partnership equity		
General partner interest	1,438	1,716
Limited partners- 21,059,141 and 19,319,362 units issued and outstanding as of June 30, 2014 and December 31, 2013, respectively	89,242	65,072
Total equity	90,680	66,788
Total liabilities and equity	$248,794	$190,083

See accompanying notes to condensed consolidated financial statements

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,	
	2014	2013	2014	2013
Revenues:				
Oil sales	$24,216	$20,926	$45,854	$40,924
Natural gas sales	119	184	288	362
Net settlements on derivatives	(2,072)	709	(2,993)	1,382
Gain (loss) on unsettled derivatives, net	(2,819)	960	(3,946)	(833)
Total revenues	19,444	22,779	39,203	41,835
Operating costs and expenses:				
Lease operating expenses	6,596	3,745	11,287	7,091
Oil and natural gas production taxes	1,493	873	2,849	1,663
Impairment of proved oil and natural gas properties	—	1,578	—	1,578
Depreciation, depletion and amortization	4,672	3,908	8,335	7,371
Accretion of discount on asset retirement obligations	59	39	111	77
General and administrative	1,725	1,289	9,356	8,037
Total operating costs and expenses	14,545	11,432	31,938	25,817
Income from operations	4,899	11,347	7,265	16,018
Other income (expense):				
Interest income and other	2	3	4	4
Interest expense	(1,054)	(812)	(1,861)	(1,425)
Total other expense	(1,052)	(809)	(1,857)	(1,421)
Net income	$3,847	$10,538	$5,408	$14,597
Computation of net income per limited partner unit:				
General partners' interest in net income	$65	$194	$93	$269
Limited partners' interest in net income	$3,782	$10,344	$5,315	$14,328
Net income per limited partner unit:				
Basic	$0.18	$0.54	$0.26	$0.75
Diluted	$0.18	$0.54	$0.26	$0.75
Weighted average limited partner units outstanding:				
Limited partner units (basic)	21,061	19,230	20,532	19,189
Limited partner units (diluted)	21,082	19,230	20,557	19,189

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Statements of Cash Flows
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
	2014	2013
Cash Flows from Operating Activities:		
Net income	$5,408	$14,597
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	8,335	7,371
Debt placement fee amortization	92	84
Accretion of discount on asset retirement obligations	111	77
Impairment of proved oil and natural gas properties	—	1,578
Loss on unsettled derivative instruments, net	3,946	833
Equity-based compensation	5,764	4,768
Changes in operating assets and liabilities:		
Accounts receivable	(1,425)	(364)
Other receivables	29	403
Prepaid and other	(201)	(363)
Accounts payable and accrued liabilities	3,400	599
Net cash provided by operating activities	25,459	29,583
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(16,062)	(14,533)
Acquisitions of oil and natural gas properties	(14,607)	(28,704)
Net cash used in investing activities	(30,669)	(43,237)
Cash Flows from Financing Activities:		
Proceeds from line of credit	61,000	66,000
Payments on line of credit	(34,000)	(33,000)
Distributions paid	(21,294)	(19,588)
Debt issuance costs	(90)	—
Net cash provided by financing activities	5,616	13,412
Net increase (decrease) in cash and cash equivalents	406	(242)
Beginning cash and cash equivalents	1,434	1,053
Ending cash and cash equivalents	$1,840	$811
Supplemental Cash Flow Information:		
Cash paid for interest	$1,823	$1,339
Non-Cash Investing and Financing Activities:		
Accrued capital expenditures - oil and natural gas properties	$785	$442
Limited partner units issued - acquisition of oil properties	$34,001	$—

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Statement of Changes in Equity
(in thousands)
(Unaudited)

		Limited Partner		
	General Partner	Units	Amount	Total Equity
Balance, December 31, 2013	$1,716	19,319	$65,072	$66,788
Equity-based compensation	—	240	5,777	5,777
Issuance of limited partner units - acquisition	—	1,500	34,001	34,001
Distributions	(371)	—	(20,923)	(21,294)
Net income	93	—	5,315	5,408
Balance, June 30, 2014	$1,438	21,059	$89,242	$90,680

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,” the "Company") is a publicly held Delaware limited partnership formed in December 2011, 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. Our limited partner 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, 2013 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 on Form 10-K for the year ended December 31, 2013.
All intercompany transactions and account balances have been eliminated.
Note 2. Acquisitions
Southern Oklahoma acquisition
During May 2014, we acquired additional working interest in some of our Southern Oklahoma core area properties ("Southern Oklahoma") for approximately $7.4 million, subject to customary post-closing adjustments. The acquisition was financed with borrowings under our revolving credit facility.
Hugoton acquisition
During February 2014, we acquired from our affiliate, Mid-Con Energy III, LLC , certain oil properties located in Cimarron, Love and Texas Counties, Oklahoma and Potter County, Texas ("Hugoton") for an aggregate price of approximately $41.0 million, subject to customary post-closing purchase price adjustments. The results of operations of these properties have been included in the unaudited condensed consolidated financial statements since the acquisition date. The transaction was primarily funded with borrowings under our revolving credit facility of approximately $7.0 million and the issuance of 1,500,000 unregistered limited partner units, which will still receive the rights of a limited partner and represent limited partner interests in us, having an approximate value of $34.0 million. The value of the limited partner units issued as partial consideration was based on a 2.5% discount to the trailing twenty day volume weighted average price of the limited partner units as of February 26, 2014. The acquisition was accounted for under the acquisition method and the assets acquired and liabilities assumed were recorded at fair market value. The purchase price for these properties represented approximately 22% of the total value of our assets as of December 31, 2013.
The recognized fair values of the Properties and liabilities assumed are as follows (in thousands):

Fair Value of net assets:	
Oil properties	$41,589
Total assets acquired	$41,589
Fair Value of net liabilities assumed:	
Asset retirement obligation	589
Net assets acquired	$41,000

Northeastern Oklahoma acquisition

In 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 consolidated financial statements since the acquisition date. We paid approximately $27.4 million in aggregate consideration for the interests and the transaction was accounted for under the acquisition method. The transaction was financed using proceeds from our revolving credit facility. The recognized fair values of the identifiable assets of the Cushing properties acquired and liabilities assumed in connection with the acquisition are as follows (in thousands):

Fair Value of net assets:	
Oil and natural gas properties	$28,318
Total assets acquired	$28,318
Fair Value of net liabilities assumed:	
Asset retirement obligation	906
Net assets acquired	$27,412

The following table reflects pro forma revenues, net income and net income per limited partner unit for the three and six months ended June 30, 2014 and 2013, as if the acquisition of the Hugoton properties had taken place on January 1, 2013. Because we took over the interests at February 28, 2014, the values for the three and six months ended June 30, 2014 are reflected in the unaudited condensed consolidated statement of operations. The pro forma financial data does not include the results of operations for the Southern Oklahoma or Northeastern Oklahoma properties, as the results of operations were deemed not to be material. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the period presented or that may be obtained in the future (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$19,444	$25,667	$41,112	$47,214
Net income	$3,847	$11,898	$5,812	$16,771
Net income per limited partner unit:				
Basic	$0.18	$0.56	$0.27	$0.80
Diluted	$0.18	$0.56	$0.27	$0.80

Note 3. Equity-Based Compensation

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, unrestricted units, 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 (the "Founders") 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. If an employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding. The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at June 30, 2014:

	Number of Common Units
Approved and authorized awards	1,764,000
Unrestricted units granted, including vested units	(803,051)
Restricted units granted, net of forfeitures and vesting	(116,090)
Phantom units issued, net of forfeitures	(40,750)
Awards available for future grant	804,109

Equity Awards
We account for restricted units as equity awards since these awards will be settled by issuing limited partner units. These restricted units vest over a three-year period and we assume a 10% forfeiture rate. A summary of our restricted units awarded for the six months ended June 30, 2014 is presented below:

Restricted awards:	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2013	120,589	
Units granted	21,000	$23.36
Units vested	(18,228)	$21.79
Units forfeited	(7,271)	$24.02
Outstanding at June 30, 2014	116,090	

We recognized $0.3 million and $6.0 million of total equity-based compensation expense for the three and six months ended June 30, 2014, respectively, and for the three and six months ended June 30, 2013 we recognized $0.2 million and $5.0 million of total equity-based compensation expense, respectively. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statement of operations.
Liability Awards
We account for phantom units issued during 2013 as liability awards due to the Long-Term Incentive Program’s provision allowing the Board of Directors, at its discretion, to settle the award in either cash or limited partner units. The phantom units are an incentive based equity award that will be issued to employees or members of the board of directors over a three-year vesting period subject to attaining certain production target levels. The phantom units are not eligible to receive quarterly distributions until they vest. The fair value of these phantom units is remeasured at the end of each reporting period based on the current market price of our common units discounted for expected forfeitures and distribution payments during the vesting period in addition to an adjustment related to management's expectation of the Partnership's ability to attain the stated production target levels. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statement of operations and are net of estimated forfeitures. These units are subject to forfeiture and we assume a 10% forfeiture rate. From the initial issuance of the the phantom units, we have recorded approximately $0.1 million of compensation expense through June 30, 2014.
Activity related to these phantom units is as follows:

Nonvested phantom awards:	Number of Units
Outstanding at December 31, 2013	43,000
Units forfeited	(2,250)
Outstanding at June 30, 2014	40,750
Units not expected to vest	(24,450)

As of June 30, 2014, there was approximately $1.7 million of unrecognized compensation costs related to non-vested units. The cost is expected to be recognized over a weighted average period of approximately 2 years. Additionally, there was approximately $0.2 million of unrecognized compensation costs related to the phantom units based on the closing price of our common units at June 30, 2014. The cost is expected to be recognized over the next 2 years.

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity prices 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, 2014, our open positions consisted of crude oil price collar (calls and puts) 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 commodity derivatives contracts as hedges for accounting purposes, therefore, the mark-to-market adjustment reflecting the change in the fair value of unsettled derivative contracts is recorded in current period earnings as a non-cash gain or loss. 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. Net settlement gains or losses on derivative contracts only arise from net payments made or received on monthly settlements or if a commodity derivative contract is terminated prior to its expiration. 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 by counterparty.

As of June 30, 2014, 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 - 2014	$93.79			2,446
Swaps - 2015	$92.83			411
Collars - 2015		$85.00	$95.13	123

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 revolving 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 unaudited condensed consolidated balance sheets at June 30, 2014 and December 31, 2013 (in thousands):

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
June 30, 2014:			
Assets			
Derivative financial instruments - current asset	$—	$—	$—
Derivative financial instruments - long-term asset	—	—	—
Total	$—	$—	$—
Liabilities			
Derivative financial instruments - current liability	$(5,372)	$—	$(5,372)
Derivative financial instruments - long-term liability	—	—	—
Total	$(5,372)	$—	$(5,372)
Net liability	$(5,372)	$—	$(5,372)

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
December 31, 2013:			
Assets			
Derivative financial instruments - current asset	$541	$388	$153
Derivative financial instruments - long-term asset	48	—	48
Total	$589	$388	$201
Liabilities			
Derivative financial instruments - current liability	$(2,015)	$(388)	$(1,627)
Derivative financial instruments - long-term liability	—	—	—
Total	$(2,015)	$(388)	$(1,627)
Net liability	$(1,426)	$—	$(1,426)

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,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net settlements on derivatives	$(2,072)	$709	$(2,993)	$1,382
Gain (loss) on unsettled derivatives, net	(2,819)	960	(3,946)	(833)

Total gain (loss) on derivatives, net	$(4,891)	$1,669	$(6,939)	$549

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 revolving credit facility approximates fair value because the revolving credit facility's variable interest rate resets frequently and approximates current market rates available to us.

We account for our oil and natural 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.

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 the estimated fair value of the asset. 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. There were no impairment charges for the three and six months ended June 30, 2014. 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.

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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, 2014 and December 31, 2013 (in thousands):

	Level 1	Level 2	Level 3
June 30, 2014			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	$—	$—	$—
Derivative financial instruments- liability	—	(5,372)	—
Net financial liabilities	$—	$(5,372)	$—
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$—	$—	$717
December 31, 2013			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	$—	$201	$—
Derivative financial instruments- liability	—	(1,627)	—
Net financial liabilities	$—	$(1,426)	$—
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	$—	$—	$879
Impairment of proved oil and natural gas properties	$—	$—	$1,578

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, 2014 and 2013.

Note 6. Asset Retirement Obligations

Our asset retirement obligations ("ARO") 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.

ARO are recorded as a liability at their estimated present value at the various assets' inception, with the offsetting charge to oil and natural gas properties. Periodic accretion of the discounted estimated liability is recorded in our 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.

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

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
	(in thousands)	
Asset retirement obligation - beginning of period	$3,942	$2,890
Liabilities incurred for new wells and interest	717	1,009
Revision of estimates	—	(130)
Accretion expense	111	173
Asset retirement obligation - end of period	$4,770	$3,942

As of June 30, 2014 and December 31, 2013, all of our ARO were classified as long-term and were reported as “Asset Retirement Obligations” in our unaudited condensed consolidated balance sheets.

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Note 7. Debt

As of June 30, 2014, our credit facility consists of a $250.0 million senior secured revolving credit facility that expires in November 2018. 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, 2014, we had $139.0 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.

Borrowings under the revolving 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, 2014, the average effective interest rate was approximately 2.81%. 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.

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 30th and October 31st 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.

During the 2013 borrowing base determination, our borrowing base under the revolving credit facility was increased from $130.0 million to $150.0 million in November 2013. Effective with this increase, the maturity terms of our revolving credit facility were extended to November 5, 2018 and the Bank of Nova Scotia ("Scotiabank") was added to the lender group. No other material terms of the original credit agreement were amended. During 2013, in connection with the amendments to our revolving credit facility, we incurred financing fees and expenses of approximately $0.4 million, which will be amortized over the life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our consolidated statements of operations.

On April 11, 2014, the borrowing base was increased from $150.0 million to $170.0 million and we incurred financing fees and expenses of approximately $0.1 million, which will be amortized over the life of the revolving credit facility. No other material terms of the original credit agreement were amended. Borrowings under the facility may not exceed our current borrowing base of $170.0 million.

The revolving 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. We were in compliance with all debt covenants throughout the period ended June 30, 2014.

Note 8. Commitment and Contingencies

We entered into 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 expire 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 1st preceding any such August 1st, for Charles R. Olmstead and Jeffrey R. Olmstead, and at least by May 1st preceding any August 1st, for S. Craig George. 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.

On May 1, 2014, the Partnership announced that Mr. S. Craig George informed the Board of Directors that he intends to resign from his role as Executive Chairman of the Board, effective August 1, 2014. Mr. George will remain as a Director of the Board.

Additionally, on May 5, 2014, the Board approved the following changes to the executive officer positions of the Partnership, effective August 1, 2014.

- Mr. Charles R. Olmstead will resign as Chief Executive Officer and will be named as Executive Chairman of the Board;
- Mr. Jeffrey R. Olmstead will resign as President and Chief Financial Officer and will assume the position of Chief Executive Officer,while remaining as a Director of the Board.
- Dr. Michael L. Wiggins will be named President & Chief Engineer, while remaining as a Director of the Board; and
- Mr. Michael D. Peterson will be named to the position of Chief Financial Officer.

Please refer to our Form 8-K filed with the SEC on May 6, 2014.

Note 9. Equity

Limited Partner Units

At June 30, 2014 and December 31, 2013, Partnership's equity consisted of 21,059,141 and 19,319,362 limited partner units, respectively, representing approximately a 98% limited partnership interest in us.

In February 2014, we issued 1,500,000 unregistered limited partner units related to the acquisition of properties from one of our affiliates. These unregistered limited partner units will still receive the rights of a limited partner and will become registered in the future. See Note 2 for an explanation of the acquisition.

Cash Distributions

The following sets forth the distributions we paid during the six months ended June 30, 2014 (in thousands, except per unit distribution):

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 14, 2014	October 1, 2013 - December 31, 2013	$0.515	$10,262
May 15, 2014	January 1, 2014 - March 31, 2014	$0.515	$11,032

On July 24, 2014, the Board of Directors of our general partner approved a quarterly cash distribution for the second quarter of 2014 of $0.515 per unit, or $2.06 on an annualized basis, which will be paid on August 11, 2014 to unitholders of record at the close of business on August 4, 2014. The aggregate amount of the distribution will be approximately $11.1 million.

Allocation of Net Income

Net income 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.

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, 2014, we reimbursed Mid-Con Energy Operating approximately \$0.7 and \$1.7 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 natural 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, fee). We and those third parties will also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements.

On February 28, 2014, we acquired from Mid-Con Energy III, LLC, an affiliated company, certain oil properties located in Cimarron, Love and Texas Counties, Oklahoma and Potter County, Texas. The terms of the acquisition were approved by the Conflicts Committee of the Board of Directors of the General Partner (the "Conflicts Committee"). The Conflicts Committee, which is composed entirely of independent directors, retained independent legal and financial counsel to assist it in evaluating and negotiating the purchase agreement and the acquisition. The purchase agreement contains representations and warranties, covenants and indemnification provisions that are typical for transactions of this nature and that were made or agreed to, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them. For more detail and information, please see Note 2 to the Unaudited Condensed Consolidated Financial Statements included herein.

On July 24, 2014, we entered into a definitive purchase and sale agreement to acquire an oil property located in Creek County, Oklahoma from Mid-Con Energy III, LLC, an affiliated company, The terms of the acquisition were approved by the Conflicts Committee. , For more detail and information, please see Note 12 to the Unaudited Condensed Consolidated Financial Statements included herein.

At June 30, 2014, we had a payable to Mid-Con Energy Operating of approximately \$5.5 million which was comprised of a joint interest billing payable of approximately \$5.2 million and a payable for operating services of approximately \$0.3 million. These amounts are included in the accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers, which provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and will supersede most current revenue recognition guidance. The standard is effective for public entities for annual and interim periods beginning after December 15, 2016. Early adoption is not permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures.

Note 12. Subsequent Events

Distributions

On July 24, 2014, the Board of Directors of our general partner approved a quarterly cash distribution for the second quarter of 2014 of $0.515 per unit, or $2.06 on an annualized basis, which will be paid on August 11, 2014 to unitholders of record at the close of business on August 4, 2014. The aggregate amount of the distribution will be approximately $11.1 million.

Acquisitions

On July 24, 2014, we entered into a definitive purchase and sale agreement (the “Purchase Agreement”) with one of our Mid-Con Affiliates, Mid-Con Energy III, LLC to acquire an oil property located in Creek County, Oklahoma for an aggregate purchase price of approximately $56.5 million, subject to customary post-closing purchase price adjustments (collectively, the “Acquisition”). The Acquisition was closed on August 5, 2014, and will have the same effective date. We paid the aggregate purchase price with (i) approximately $4.5 million in cash, financed through borrowings under our revolving credit facility, and (ii) the issuance of 2,214,659 unregistered common units representing limited partner interests in the Partnership, having an approximate value of $52.0 million. The value of the common units issued as partial consideration for the Acquisition was based on the trailing ten day volume weighted average price of the common units.

The terms of the Purchase Agreement were approved by the Conflicts Committee . The Conflicts Committee, which is composed entirely of independent directors, retained independent legal and financial counsel to assist in evaluating and negotiating the Purchase Agreement and the Acquisition. The purchase agreement contains representations and warranties, covenants and indemnification provisions that are typical for transactions of this nature and that were made or agreed to, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them.

On August 4, 2014, we entered into a definitive purchase and sale agreement to acquire working interests in the South Liberty Waterflood Unit in Liberty County, Texas for an aggregate purchase price of approximately $19.4 million. The acquisition is expected to close on August 29, 2014.

Commodity Derivatives

During July 2014, we entered into a series of oil derivative contracts covering a total of; (1) approximately 150,000 barrels of future production between January and March 2015 with a weighted average price of $95.73 per barrel, (2) approximately 150,000 barrels of future production between April and June 2015 with a weighted average price of $95.00 per barrel and (3) approximately 120,000 barrels of future production between July and December 2015 with a weighted average price of $91.04 per barrel.

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 publicly held Delaware limited partnership focused on the acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on Enhanced Oil Recovery ("EOR"). Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our limited partner units are traded on the NASDAQ Global Select Market under the symbol "MCEP".

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, Texas and Colorado within the Hugoton area. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

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 11, 2014, the borrowing base under the revolving credit facility was increased from $150.0 million to $170.0 million. No other material terms of the original credit agreement were amended.

On May 1, 2014, we acquired additional working interest in some of our Southern Oklahoma core area properties for approximately $7.4 million, subject to customary post-closing adjustments. The acquisition was financed with borrowings under our revolving credit facility.

On May 15, 2014, we paid a cash distribution to unitholders for the first quarter of 2014 at the rate of $0.515 per unit. The aggregate distribution was approximately $11.0 million.

Departure of Certain Officers

On May 1, 2014, Mid-Con Energy Partners, LP (the "Partnership") announced that Mr. S. Craig George informed the Board of Directors that he will resign from his role as Executive Chairman of the Board, effective August 1, 2014. Mr. George will remain as a Director of the Board.

Appointment of Certain Officers

On May 5, 2014, the Board of the General Partner approved the following changes to the executive officer positions, to be effective August 1, 2014:

- Mr. Charles R. Olmstead will resign as Chief Executive Officer and will be named as Executive Chairman of the Board;
- Mr. Jeffrey R. Olmstead will resign as President and Chief Financial Officer, and will assume the position of Chief Executive Officer immediately following Mr. Charles R. Olmstead's resignation, while remaining as a Director of the Board;
- Dr. Michael L. Wiggins will be named President & Chief Engineer, while remaining as a Director of the Board; and
- Mr. Michael D. Peterson will be named to the position of Chief Financial Officer.

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 commodity market volatility. 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 commodity 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. Our focus on adding reserves is 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.

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.

Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated (dollars in thousands, except price per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues:				
Oil sales	$24,216	$20,926	$45,854	$40,924
Natural gas sales	119	184	288	362
Net settlements on derivatives	(2,072)	709	(2,993)	1,382
Gain (loss) on unsettled derivatives, net	(2,819)	960	(3,946)	(833)
Total revenues	$19,444	$22,779	$39,203	$41,835
Operating costs and expenses:				
Lease operating expenses	$6,596	$3,745	$11,287	$7,091
Oil and natural gas production taxes	$1,493	$873	$2,849	$1,663
Impairment of proved oil and natural gas properties	$—	$1,578	$—	$1,578
Depreciation, depletion and amortization	$4,672	$3,908	$8,335	$7,371
General and administrative (1)	$1,725	$1,289	$9,356	$8,037
Interest expense	$1,054	$812	$1,861	$1,425
Production:				
Oil (MBbls)	245	230	477	450
Natural gas (MMcf)	19	36	40	73
Total (MBoe)	248	236	484	462
Average net production (Boe/d)	2,725	2,593	2,674	2,552
Average sales price:				
Oil (per Bbl):				
Sales price	$98.84	$90.98	$96.13	$90.94
Effect of net settlements on commodity derivative instruments	$(8.46)	$3.08	$(6.27)	$3.07
Realized oil price after derivatives	$90.38	$94.06	$89.86	$94.01
Natural gas (per Mcf):				
Sales price (2)	$6.26	$5.11	$7.20	$4.96
Average unit costs per Boe:				
Lease operating expenses	$26.60	$15.87	$23.32	$15.35
Oil and natural gas production taxes	$6.02	$3.70	$5.89	$3.60
Depreciation, depletion and amortization	$18.84	$16.56	$17.22	$15.95
General and administrative expenses	$6.96	$5.46	$19.33	$17.40

(1) General and administrative expenses include non-cash, equity-based compensation of $0.3 million and $5.8 million for the three and six months ended June 30, 2014; and $0.1 million and $4.8 million for the three and six months ended June 30, 2013, respectively.

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

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013

Net income was approximately $3.8 million for the three months ended June 30, 2014, compared to approximately $10.5 million for the three months ended June 30, 2013, a decrease of approximately $6.7 million. The change was primarily attributable to the unfavorable net effect of our derivatives, an increase in lease operating expenses, depreciation, depletion and amortization, and production taxes, partially offset by an increase in oil sales during the three months ended June 30, 2014.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended June 30, 2014, were approximately $24.3 million compared to approximately $21.1 million for the three months ended June 30, 2013. The increase in revenues was primarily due to higher sales prices along with an increase in daily oil production from drilling efforts and incremental volumes from acquisitions of additional working interests in May 2013 and from the acquisition of additional oil properties in February 2014.

On average, our production volumes for the three months ended June 30, 2014, were approximately 248 MBoe, or approximately 2,725 Boe per day on average. In comparison, our total production volumes for the three months ended June 30, 2013, were approximately 236 MBoe, or approximately 2,593 Boe per day on average. The increase in production volumes was primarily due to the acquisition of additional oil properties from our affiliate in February 2014. Our legacy assets' production declined due to natural declines and converting some producers to injectors but was offset by the production from the acquisitions of additional working interest in May 2013 and the acquisition of additional oil properties in February 2014. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended June 30, 2014, was approximately $98.84, compared with approximately $90.98 for the three months ended June 30, 2013.

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 loss of approximately $4.9 million from our commodity hedging instruments for the three months ended June 30, 2014, which was composed of approximately $2.1 million loss on net cash settlements of derivative contracts and approximately $2.8 million non-cash loss on unsettled derivative contracts. For the three months ended June 30, 2013, we recorded a net gain from our commodity hedging instruments of approximately $1.7 million, which was composed of a gain of approximately $0.7 million on net cash settlements of derivative contracts and approximately $1.0 million non-cash gain on unsettled derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $6.6 million for the three months ended June 30, 2014, or approximately $26.60 per Boe, compared to approximately $3.7 million for the three months ended June 30, 2013, or approximately $15.87 per Boe. The increase in total lease operating expenses over the prior year’s quarter was primarily attributable to the acquisition of additional working interests in May 2013, the acquisition of additional oil properties in February 2014 , the recent acquisition of additional working interests in May 2014 and the additional number of producing wells resulting from our drilling programs. The increase in average costs per Boe reflects higher costs of operations in comparison to the proportional increase in production. The higher operating costs were generated in our Hugoton Basin, Northeastern Oklahoma and Southern Oklahoma areas during the current period including additional workover costs of approximately $0.8 million for the three months ended June 30, 2014 as compared to $21,000 of workover costs 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. For the three months ended June 30, 2014, our production taxes were approximately $1.5 million, or approximately $6.02 per Boe for an effective tax rate of approximately 6.1%, compared to 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%. The increase in both the production tax rate and price per Boe during the three months ended June 30, 2014 was related to the expiration of a reduced production tax on a large majority of our production that qualified for the Oklahoma Enhanced Recovery Project Gross Production Tax Exemption, the acquisition of additional working interests during 2013 and the recently acquired oil properties in February 2014. 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. There was no impairment charge for the three months ended June 30, 2014. For the three months ended June 30, 2013, we recorded approximately a $1.6 million non-cash impairment charge within our miscellaneous core area properties resulting from declines in reserve estimates. 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.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses (“DD&A”) on producing properties for the three months ended June 30, 2014, were approximately $4.7 million, or approximately $18.84 per Boe produced, compared to approximately $3.9 million, or approximately $16.56 per Boe produced, for the three months ended June 30, 2013. The increase in DD&A expenses was primarily due to the acquisition of additional working interests in May 2013 and oil properties acquired in February 2014.
General and Administrative Expenses. Our general and administrative expenses were approximately $1.7 million for the three months ended June 30, 2014, or approximately $6.96 per Boe produced, compared to approximately $1.3 million for the three months ended June 30, 2013 or approximately $5.46 per Boe produced. The overall increase in general and administrative expenses for the three months ended June 30, 2014 was primarily due to higher non-recurring legal and professional services costs related to the acquisition in February 2014 and to our Registration Statement filed in May 2014. Non-cash equity based compensation expense was $0.3 million and $0.1 million for the three months ended June 30, 2014 and 2013, respectively.
Interest Expense. Our interest expense for the three months ended June 30, 2014, was approximately $1.1 million, compared to $0.8 million for the three months ended June 30, 2013. The increase in interest expense during the three months ended June 30, 2014 compared to the three months ended June 30, 2013 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions in 2013 and 2014.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013
Net income was approximately $5.4 million for the six months ended June 30, 2014 compared to approximately $14.6 million for the six months ended June 30, 2013, a decrease of approximately $9.2 million. This decrease primarily reflects the unfavorable net 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 lease operating expenses, partially offset by an increase in oil sales during the six months ended June 30, 2014.

Sales Revenues. Revenues from oil and natural gas sales for the six months ended June 30, 2014 were approximately $46.1 million as compared to approximately $41.3 million for the six months ended June 30, 2013. The increase in revenues was primarily due to higher sales prices along with 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, 2014 were approximately 484 MBoe, or approximately 2,674 Boe per day. In comparison, our total production volumes for the six months ended June 30, 2013, were approximately 462 MBoe, or approximately 2,552 Boe per day. Our legacy assets' production declined due to natural declines and converting some producers to injectors but was offset by the production from the acquisitions of additional working interest in May 2013 and the acquisition of additional oil properties in February 2014. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the six months ended June 30, 2014 was $96.13, compared with $90.94 for the six months ended June 30, 2013.

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 loss of approximately $6.9 million from our commodity hedging instruments for the six months ended June 30, 2014, which was composed of approximately $3.0 million loss on net cash settlements of derivative contracts and approximately $3.9 million non-cash loss on unsettled derivative contracts. For the six months ended June 30, 2013, we recorded a net gain from our commodity hedging instruments of approximately $0.6 million, which was composed of approximately $1.4 million gain on net cash settlements of derivative contracts and a non-cash loss on unsettled derivative contracts of approximately $0.8 million.

Lease Operating Expenses. Our lease operating expenses were approximately $11.3 million for the six months ended June 30, 2014, or $23.32 per Boe, compared to approximately $7.1 million for the six months ended June 30, 2013, or approximately $15.35 per Boe. The increase in total lease operating expenses and average costs per Boe was primarily attributable to the acquisition of additional working interests in May 2013, the acquisition of additional oil properties in February 2014, the recent acquisition of additional working interests in May 2014 and the additional number of producing wells resulting from our drilling programs. The increase in average costs per Boe reflects higher costs of operations in comparison to the proportional increase in production. The higher operating costs were generated in our Hugoton Basin, Northeastern Oklahoma and Southern Oklahoma areas, including additional workover costs of approximately $1.0 million, for the six months ended June 30, 2014 as compared to six 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. For the six months ended June 30, 2014, our production taxes were approximately $2.8 million for the six months ended June 30, 2014, or approximately $5.89 per Boe for an effective tax rate of approximately 6.2%, compared to 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%. The increase in both the production taxes and price per Boe during the six months ended June 30, 2014 was related to the expiration of a reduced production tax on a large majority of our production that qualified for the Oklahoma Enhanced Recovery Project Gross Production Tax Exemption, the acquisition of additional working interests during 2013 and the acquisition of oil properties in February 2014. 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. There was no impairment charge for the six months ended June 30, 2014. For the six months ended June 30, 2013, we recorded approximately a $1.6 million non-cash impairment charge within our miscellaneous core area properties resulting from declines in reserve estimates. 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.

Depreciation, Depletion and Amortization Expenses. Our DD&A on producing properties for the six months ended June 30, 2014, was approximately $8.3 million, or approximately $17.22 per Boe produced, compared to approximately $7.4 million, or approximately $15.95 per Boe produced, for the six months ended June 30, 2013. The increase in DD&A expenses was primarily due to the increase in total asset value of the oil and natural gas properties from the acquisition of additional working interests in May 2013 and oil properties acquired in February 2014.

General and Administrative Expenses. Our general and administrative expenses were approximately $9.4 million for the six months ended June 30, 2014, or approximately $19.33 per Boe produced, compared to approximately $8.0 million for the six months ended June 30, 2013 or approximately $17.40 per Boe produced. The overall increase in general and administrative expenses for the six months ended June 30, 2014 was primarily due to an increase in compensation costs related to our non-cash equity-based compensation plan. Non-cash equity based compensation expense was $5.8 million and $4.8 million for the six months ended June 30, 2014 and 2013, respectively.

Interest Expense. Our interest expense for the six months ended June 30, 2014 was approximately $1.9 million, compared to approximately $1.4 million for the six months ended June 30, 2013. The increase in interest expense during the six months ended June 30, 2014 compared to the six months ended June 30, 2013 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions in 2013 and 2014.

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, 2014, consisted of approximately $1.8 million of available cash, and $31.0 million of available borrowings under our revolving 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 revolving credit facility.

On April 11, 2014, the borrowing base of our revolving credit facility was increased from $150.0 million to $170.0 million. No other material terms of the original credit agreement were amended. As of June 30, 2014, our $250.0 million revolving credit facility had a remaining borrowing capacity of $31.0 million ($170.0 million borrowing base less $139.0 million of outstanding borrowings). The borrowing base is re-determined on or about April 30th and October 31st of each year.

Cash Flow

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

	Six Months Ended June 30,	
	2014	2013
Operating activities	$25,459	$29,583
Investing activities	(30,669)	(43,237)
Financing activities	5,616	13,412

Operating Activities. Net cash provided by operating activities was approximately $25.5 million and $29.6 million for the six months ended June 30, 2014 and 2013, respectively. The $4.1 million decrease from 2013 to 2014 was primarily attributable to higher lease operating expenses and production taxes offset by higher oil sales. Our net cash provided by operating activities also includes a reduction of $1.5 million associated with changes in working capital items from 2013 to 2014. 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, increased production through our drilling programs, acquisitions, and results of future capital expenditures.

Investing Activities. Net cash used in investing activities was approximately $30.7 million and approximately $43.2 million for the six months ended June 30, 2014 and 2013, respectively. Cash used in investing activities during the six months ended June 30, 2014 included approximately $14.6 million for the acquisition of oil properties and additional working interests. We also spent $16.1 million on capital expenditures, primarily for drilling, development and completion activities. Cash used in investing activities during the six months ended June 30, 2013 included approximately $28.7 million for the acquisition of additional working interests. We also spent $14.5 million on capital expenditures, primarily for drilling, development and completion activities.

Financing Activities. Our cash flows from financing activities consisted primarily of proceeds from and payments on our revolving credit facility, and distributions to unitholders. Net cash provided by financing activities was approximately $5.6 million and approximately $13.4 million for the six months ended June 30, 2014 and 2013, respectively. During the six months ended June 30, 2014, cash provided by financing activities included net proceeds of approximately $27.0 million from borrowings under our revolving credit facility which were used to finance the acquisition of properties in February 2014 and May 2014 and to develop capital projects. We also made cash distributions to our unitholders of approximately $21.3 million. Cash provided by financing activities during the six months ended June 30, 2013, included net proceeds from borrowings under our revolving credit facility of $33.0 million which were used to finance the acquisition of additional working interests in our Northeastern and Southern Oklahoma core areas and to develop capital projects. We also made cash distributions to our unitholders of approximately $19.6 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, available borrowing capacity under our current revolving credit facility and the issuance of limited partner units. We expect to finance any significant acquisition of oil and natural gas properties in 2014 through the issuance of equity, debt financing or borrowings under our revolving credit facility. Additionally, we currently expect capital spending for the remainder of 2014 for the development, growth and maintenance of our oil and natural gas properties to be approximately $11.5 million.

Revolving Credit Facility

We have a $250.0 million senior secured revolving credit facility that expires in November 2018. 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, 2014, we had approximately $139.0 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. We were in compliance with all of the facility’s financial covenants throughout the period ended June 30, 2014.

During the 2013 borrowing base redeterminations, our borrowing base under the revolving credit facility was increased from $130.0 million to $150.0 million and Scotiabank was added to the lender group. Effective with this increase, the maturity terms of our revolving credit facility were extended to November 2018. No other material terms of the original credit agreement were amended. The borrowing base is determined by the lenders based on our oil and natural gas reserves.

On April 11, 2014, the borrowing base under the revolving credit facility was increased from $150.0 million to $170.0 million. No other material terms of the original credit agreement were amended. Borrowings under the facility may not exceed our current borrowing base of $170.0 million.

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, 2014, our open commodity derivative contracts were in a net liability position with a fair value of approximately $5.4 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, 2014, all of our counterparties had performed pursuant to their commodity derivative contracts.

All of our derivative contracts for 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 for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of unsettled derivative contracts is recorded in current period earnings as a net non-cash gain or loss on unsettled derivatives. When prices for oil are volatile, a significant portion of the effect of our hedging activities consists of non-cash gains or losses due to changes in the fair value of our commodity derivative contracts. Net settlement gains or losses on derivative contracts only arise from net payments made or received on monthly settlements or if a commodity derivative contract is terminated prior to its expiration and are reported as net settlements on derivatives in the unaudited condensed consolidated statement of operations.

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, 2014, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements
In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers, which provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and will supersede most current revenue recognition guidance. The standard is effective for public entities for annual and interim periods beginning after December 15, 2016. Early adoption is not permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures.

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 Form10-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 and changes in supply and demand.
To reduce the impact of fluctuations in oil prices on our revenues, or to protect the economics of property acquisitions, we have entered into, and may enter into, additional commodity derivative contracts for a portion of our oil production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil production over a fixed period of time. 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 revolving credit facility and have investment grade ratings. We expect to enter into future derivative contracts with these or other lenders under our revolving credit facility whom we expect will also carry investment grade ratings.
Our commodity price risk management activities could have the effect of reducing net income and the value of our securities. The fair value of our oil commodity contracts and swaps at June 30, 2014, was a net liability of approximately $5.4 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 $6.2 million. Please see “Item 1. Financial Statements” contained herein for additional information.
Interest Rate Risk
At June 30, 2014, we had long-term debt outstanding of $139.0 million, with an effective interest rate of approximately 2.7%. 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 $0.2 million on a semi-annual basis. Our revolving credit facility allows borrowings up to $170.0 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 2014 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, 2014. 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, 2014, 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, 2013.
ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS
See our current reports on Form 8-K filed with the SEC on March 5, 2014 and July 25, 2014.
ITEM 3. DEFAULTS UPON SENIOR SECURITIES
None.
ITEM 4. MINE SAFETY DISCLOSURES
Not applicable.
ITEM 5. OTHER INFORMATION
None.

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.4 to Credit Agreement, dated as of April 11, 2014, 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 10.01 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on April 15, 2014).
10.2	Purchase and Sale Agreement, dated February 28, 2014, by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on March 5, 2014).
10.3	Purchase and Sale Agreement, dated July 24, 2014, by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on July 25, 2014).
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.”

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
August 5, 2014	By:	/s/ Michael D. Peterson Michael D. Peterson Chief Financial Officer