

Mid-Con Energy Partners, LP
Form 10-Q
November 03, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended September 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 (I.R.S. Employer
incorporation or organization) 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 ☒ 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 ☒ 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 ☒

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

As of November 3, 2014, the registrant had 23,336,578 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 website, 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)

	September 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$1,570	\$1,434
Accounts receivable:		
Oil and natural gas sales	8,495	6,778
Other	222	104
Derivative financial instruments	4,261	153
Prepays and other	286	191
Total current assets	14,834	8,660
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, successful efforts method:		
Proved properties	366,692	216,680
Accumulated depletion, depreciation and amortization	(50,048)	(36,148)
Total property and equipment, net	316,644	180,532
DERIVATIVE FINANCIAL INSTRUMENTS	407	48
OTHER ASSETS	869	843
Total assets	\$332,754	\$190,083
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	\$2,592	\$2,184
Related parties	6,706	2,982
Derivative financial instruments	—	1,627
Accrued liabilities	189	432
Total current liabilities	9,487	7,225
OTHER LONG-TERM LIABILITIES	108	128
LONG-TERM DEBT	168,000	112,000
ASSET RETIREMENT OBLIGATIONS	5,401	3,942
COMMITMENTS AND CONTINGENCIES		
EQUITY, per accompanying statements:		
Partnership equity		
General partner interest	1,534	1,716
Limited partners- 23,337,511 and 19,319,362 units issued and outstanding as of September 30, 2014 and December 31, 2013, respectively	148,224	65,072
Total equity	149,758	66,788
Total liabilities and equity	\$332,754	\$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 September 30,		Nine Months Ended September 30,		
	2014	2013	2014	2013	
Revenues:					
Oil sales	\$26,011	\$22,831	\$71,865	\$63,755	
Natural gas sales	162	151	450	513	
Net settlements on derivatives	(760	) (1,293	) (3,753	) 89	
Gain (loss) on unsettled derivatives, net	10,040	(5,501	) 6,094	(6,334	)
Total revenues	35,453	16,188	74,656	58,023	
Operating costs and expenses:					
Lease operating expenses	6,849	4,768	18,136	11,859	
Oil and natural gas production taxes	1,845	1,007	4,694	2,670	
Impairment of proved oil and natural gas properties	303	—	303	1,578	
Depreciation, depletion and amortization	5,565	3,586	13,900	10,957	
Accretion of discount on asset retirement obligations	64	47	175	124	
General and administrative	2,602	1,630	11,958	9,667	
Total operating costs and expenses	17,228	11,038	49,166	36,855	
Income from operations	18,225	5,150	25,490	21,168	
Other income (expense):					
Interest income and other	3	2	7	6	
Interest expense	(1,226	) (895	) (3,087	) (2,320	)
Total other expense	(1,223	) (893	) (3,080	) (2,314	)
Net income	\$17,002	\$4,257	\$22,410	\$18,854	
Computation of net income per limited partner unit:					
General partners' interest in net income	\$268	\$77	\$375	\$346	
Limited partners' interest in net income	\$16,734	\$4,180	\$22,035	\$18,508	
Net income per limited partner unit:					
Basic	\$0.75	\$0.22	\$1.04	\$0.96	
Diluted	\$0.74	\$0.22	\$1.04	\$0.96	
Weighted average limited partner units outstanding:					
Limited partner units (basic)	22,450	19,269	21,175	19,213	
Limited partner units (diluted)	22,467	19,296	21,198	19,219	

See accompanying notes to condensed consolidated financial statements

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

	Nine Months Ended September 30,	
	2014	2013
Cash Flows from Operating Activities:		
Net income	\$22,410	\$18,854
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	13,900	10,957
Debt issuance costs amortization	144	126
Accretion of discount on asset retirement obligations	175	124
Impairment of proved oil and natural gas properties	303	1,578
(Gain) loss on unsettled derivative instruments, net	(6,094)	) 6,334
Equity-based compensation	6,900	5,419
Changes in operating assets and liabilities:		
Accounts receivable	(1,717)	) (603)
Other receivables	(118)	) 603
Prepays and other	(95)	) (259)
Accounts payable and accrued liabilities	3,772	(648)
Net cash provided by operating activities	39,580	42,485
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(24,079)	) (19,146)
Acquisitions of oil and natural gas properties	(38,834)	) (28,022)
Net cash used in investing activities	(62,913)	) (47,168)
Cash Flows from Financing Activities:		
Proceeds from line of credit	109,000	87,000
Payments on line of credit	(53,000)	) (53,000)
Distributions paid	(32,361)	) (29,711)
Debt issuance costs	(170)	) —
Net cash provided by financing activities	23,469	4,289
Net increase (decrease) in cash and cash equivalents	136	(394)
Beginning cash and cash equivalents	1,434	1,053
Ending cash and cash equivalents	\$1,570	\$659
Supplemental Cash Flow Information:		
Cash paid for interest	\$3,156	\$2,200
Non-Cash Investing and Financing Activities:		
Accrued capital expenditures - oil and natural gas properties	\$1,043	\$373
Limited partner units issued - acquisition of oil properties	\$86,001	\$—
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)

	General Partner	Limited Partner Units	Amount	Total Equity
Balance, December 31, 2013	\$1,716	19,319	\$65,072	\$66,788
Equity-based compensation	—	304	6,920	6,920
Issuance of limited partner units - acquisitions	—	3,714	86,001	86,001
Distributions	(556	) —	(31,805	) (32,361
Net income	374	—	22,036	22,410
Balance, September 30, 2014	\$1,534	23,337	\$148,224	\$149,758
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 July 2011, that engages in the acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on Enhanced Oil Recovery ("EOR"). 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

Creek County, Oklahoma acquisition

During August 2014, we acquired from our affiliate, Mid-Con Energy III, LLC, a certain oil property located in Creek County, Oklahoma for an aggregate price of approximately \$56.5 million, subject to customary post-closing purchase price adjustments. The results of operations of this property 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 \$4.5 million in cash and the issuance of 2,214,659 unregistered limited partner units having an approximate value of \$52.0 million. The acquisition was accounted for under the acquisition method and the assets acquired and liabilities assumed were recorded at fair market value.

The recognized fair values of the property acquired and liabilities assumed are as follows (in thousands):

Fair Value of net assets:

Oil property	\$57,074
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Total assets acquired	\$57,074
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Fair Value of net liabilities assumed:

Asset retirement obligation	574
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Net assets acquired	\$56,500
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Liberty County, Texas acquisition

During August 2014, we acquired a waterflood unit in Liberty County, Texas for approximately \$19.4 million, subject to customary post-closing adjustments. The acquisition was financed with borrowings under our revolving credit facility.

Southern Oklahoma acquisition

During May 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.

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. 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 having an approximate value of \$34.0 million. The acquisition was accounted for under the acquisition method and the assets acquired and liabilities assumed were recorded at fair market value. The recognized fair values of the Hugoton properties acquired 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 nine months ended September 30, 2014 and 2013, as if the acquisitions of the Creek County property and Hugoton properties had taken place on January 1, 2013. Because we took over the interests at August 1, 2014 for the Creek County property, the values for August and September 2014 are included in the unaudited condensed consolidated statement of operations. Because we took over the interests at February 28, 2014 for the Hugoton properties, the values for March 2014 through September 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 Liberty County, Texas, 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	\$36,647	\$22,565	\$84,436	\$74,202
Net income	\$17,915	\$7,385	\$28,018	\$25,614
Net income per limited partner unit:				
Basic	\$0.76	\$0.32	\$1.19	\$1.10
Diluted	\$0.76	\$0.32	\$1.19	\$1.10

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 September 30, 2014:

	Number of Common Units
Approved and authorized awards	1,764,000
Unrestricted units granted, including vested restricted units	(866,253)
Restricted units granted, net of forfeitures and vesting	(116,599)
Phantom units issued, net of forfeitures	(25,666)
Awards available for future grant	755,482

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 nine months ended September 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	53,375	\$23.11
Units vested	(44,430)	\$23.09
Units forfeited	(12,935)	\$23.52
Outstanding at September 30, 2014	116,599	

We account for unrestricted units as equity awards since these awards will be settled by issuing limited partner units. A summary of our unrestricted units awarded for the nine months ended September 30, 2014 is presented below:

Unrestricted awards:	Number of Unrestricted Units	Average Grant Date Fair Value per Unit
Unrestricted units granted at December 31, 2013	558,773	
Unrestricted units granted	263,050	\$23.30
Restricted units vested	44,430	\$23.09
Total unrestricted units at September 30, 2014	866,253	

We recognized \$1.1 million and \$7.1 million of total equity-based compensation expense for the three and nine months ended September 30, 2014, respectively, and for the three and nine months ended September 30, 2013 we recognized \$0.6 million and \$5.6 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 limited partner 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 September 30, 2014.

Activity related to these phantom units is as follows:

	Number of Units
Nonvested phantom awards:	
Outstanding at December 31, 2013	43,000
Units forfeited	(17,334)
Outstanding at September 30, 2014	25,666
Outstanding units not expected to vest	(16,812)

As of September 30, 2014, there was approximately \$1.9 million of unrecognized compensation costs related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.9 years. Additionally, there was approximately \$0.1 million of unrecognized compensation costs related to the phantom units based on the closing price of our common units at September 30, 2014. The cost is expected to be recognized over the next 1.7 years.

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity price volatility 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 or physical delivery points and NYMEX futures prices. Our policies do not permit the use of derivatives for speculative purposes.

At September 30, 2014, our open positions consisted of 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.

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 September 30, 2014, we had the following oil derivative open positions:

Period Covered	Weighted Average Fixed Price	Total Bbls Hedged/day
Swaps - 2014	\$93.79	2,446
Swaps - 2015	\$93.29	1,932
Swaps - 2016	\$90.20	82

In July 2014, we restructured 123 barrels per day of 2015 crude oil collar contracts into 2015 swap contracts covering the same volumes. These restructurings were effected between contracts of equal value and accordingly, did not require any cash settlements.

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 credit 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 September 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
September 30, 2014:			
Assets			
Derivative financial instruments - current asset	\$4,290	\$29	\$4,261
Derivative financial instruments - long-term asset	407	—	407
Total	\$4,697	\$29	\$4,668
Liabilities			
Derivative financial instruments - current liability	\$(29)	) \$(29	) \$—
Derivative financial instruments - long-term liability	—	—	—
Total	\$(29	) \$(29	) \$—
Net asset	\$4,668	\$—	\$4,668

	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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net settlements on derivatives	\$(760)	\$(1,293)	\$(3,753)	\$89
Gain (loss) on unsettled derivatives, net	10,040	(5,501)	6,094	(6,334)
Total gain (loss) on derivatives, net	\$9,280	\$(6,794)	\$2,341	\$(6,245)

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our balance sheet for cash, accounts receivable and accounts payable 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 derivative financial instruments 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. During the three and nine months ended September 30, 2014, we recorded a non-cash impairment charge of \$0.3 million within our Southern Oklahoma core area due to a decline in reserve estimates. There were no impairment charges for the three months ended September 30, 2013. During the nine months ended September 30, 2013, we recorded a non-cash impairment charge of \$1.6 million within

our miscellaneous core area due to a decline in reserve estimates.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value as of September 30, 2014 and December 31, 2013 (in thousands):

	Level 1	Level 2	Level 3
September 30, 2014			
Assets and Liabilities Measured at Fair Value on a Recurring Basis			
Derivative financial instruments- asset	\$—	\$4,668	\$—
Derivative financial instruments- liability	—	—	—
Net financial assets	\$—	\$4,668	\$—
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis			
Asset retirement obligations	\$—	\$—	\$1,284
Impairment of proved oil and natural gas properties	\$—	\$—	\$303
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 nine months ended September 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:

	Nine Months Ended September 30, 2014 (in thousands)	Year Ended December 31, 2013
Asset retirement obligation - beginning of period	\$3,942	\$2,890
Liabilities incurred for new wells and interest	1,284	1,009
Revision of estimates	—	(130)
Accretion expense	175	173
Asset retirement obligation - end of period	\$5,401	\$3,942

As of September 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.

Note 7. Debt

As of September 30, 2014, our credit facility consists of a \$250.0 million senior secured revolving credit facility that expires in November 2018. Borrowings under the revolving credit facility may not exceed our current borrowing base of \$190.0 million as determined at August 29, 2014. 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 September 30, 2014, we had \$168.0 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 September 30, 2014, the average effective interest rate was approximately 2.83%. 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 November 2013 borrowing base determination, our borrowing base under the revolving credit facility was increased from \$130.0 million to \$150.0 million. 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 are 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. No other material terms of the original credit agreement were amended. In connection with the amendment to our revolving credit facility, we incurred financing fees and expenses of approximately \$0.1 million, which are amortized over the life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our consolidated statements of

operations. No other material terms of the original credit agreement were amended.

On August 29, 2014, the borrowing base was increased from \$170.0 million to \$190.0 million and we incurred financing fees and expenses of approximately \$0.1 million, which are amortized over the life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our consolidated statements of operations. No other material terms of the original credit agreement were amended.

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 September 30, 2014.

Note 8. Commitments and Contingencies

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

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

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

Note 9. Equity

Limited Partner Units

At September 30, 2014 and December 31, 2013, the Partnership's equity consisted of 23,337,511 and 19,319,362 limited partner units, respectively, representing approximately a 98% limited partnership interest in us.

In February 2014 and August 2014, we issued 1,500,000 and 2,214,659 unrestricted limited partner units, respectively, related to the acquisition of properties from one of our affiliates. See Note 2 for an explanation of these acquisitions.

Cash Distributions

The following sets forth the distributions we paid during the nine months ended September 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
August 11, 2014	April 1, 2014 - June 30, 2014	\$0.515	\$11,067
			\$32,361

On October 22, 2014, the Board of Directors of our general partner approved a quarterly cash distribution for the third quarter of 2014 of \$0.515 per unit, or \$2.06 on an annualized basis, which will be paid on November 14, 2014 to unitholders of record at the close of business on November 3, 2014. The aggregate amount of the distribution will be

approximately \$12.2 million.

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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 nine months ended September 30, 2014, we reimbursed Mid-Con Energy Operating approximately \$0.8 and \$2.5 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.

During February and August, 2014, we acquired from Mid-Con Energy III, LLC, an affiliated company, certain oil properties located in Oklahoma and Texas. The terms of the acquisitions 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 agreements and the acquisitions. The purchase agreements contained 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.

At September 30, 2014, we had a payable to Mid-Con Energy Operating of approximately \$6.7 million which was comprised of a joint interest billing payable of approximately \$6.4 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 October 22, 2014, the Board of Directors of our general partner approved a quarterly cash distribution for the third quarter of 2014 of \$0.515 per unit, or \$2.06 on an annualized basis, which will be paid on November 14, 2014 to unitholders of

record at the close of business on November 3, 2014. The aggregate amount of the distribution will be approximately \$12.2 million.

Acquisitions

On October 7, 2014, we entered into a definitive purchase and sale agreement to acquire multiple oil and natural gas properties covering approximately 18,000 net acres located in Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall, Taylor, and Tom Green Counties, Texas ("Eastern Shelf Acquisition") for an aggregate purchase price of approximately \$120.0 million, subject to customary post-closing adjustments. The acquisition is expected to close in November 2014, with an effective date of September 1, 2014. Please refer to our Form 8-K filed with the SEC on October 14, 2014.

Revolving Credit Facility

Contingent upon completion of the Eastern Shelf Acquisition, the Partnership has secured lender commitments to increase its borrowing base to \$240.0 million, up 26% from the \$190.0 million in commitments established under its existing revolving credit facility. The borrowing base increase will become effective upon closing of the acquisition, at which time a \$100.0 million Second Lien Term Loan, maturing in May of 2019, will also become available to the Partnership. The borrowing base increase and senior secured Second Lien Term Loan have been fully underwritten by the Royal Bank of Canada acting in its capacity as Administrative Agent along with other participating lenders.

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 core areas are located in: Southern Oklahoma, Northeastern Oklahoma, the Gulf Coast, and Hugoton.

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 August 5, 2014, we acquired from our affiliate, Mid-Con Energy III, LLC, a certain oil property located in Creek County, Oklahoma for an aggregate price of approximately \$56.5 million, subject to customary post-closing purchase price adjustments. The acquisition was primarily funded with borrowings under our revolving credit facility of approximately \$4.5 million in cash and the issuance of 2,214,659 limited partner units having an approximate value of \$52.0 million.

On August 11, 2014, we paid a cash distribution to unitholders for the second quarter of 2014 at the rate of \$0.515 per unit. The aggregate distribution was approximately \$11.1 million.

On August 29, 2014, we acquired a waterflood unit in Liberty County, Texas for an aggregate purchase price of approximately \$19.4 million, subject to customary post-closing adjustments. The acquisition was financed with borrowings under our revolving credit facility.

On August 29, 2014, the borrowing base under the revolving credit facility was increased from \$170.0 million to \$190.0 million. No other material terms of the original credit agreement were amended.

Appointment of Certain Officers

Effective August 1, 2014 the executive officer positions were changed as below:

- Mr. Charles R. Olmstead assumed Executive Chairman of the Board;
- Mr. Jeffrey R. Olmstead assumed the position of Chief Executive Officer, while remaining as a Director of the Board;
- Dr. Michael L. Wiggins assumed President & Chief Engineer, while remaining as a Director of the Board; and
- Mr. Michael D. Peterson assumed 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues:				
Oil sales	\$26,011	\$22,831	\$71,865	\$63,755
Natural gas sales	162	151	450	513
Net settlements on derivatives	(760)	) (1,293	) (3,753	) 89
Gain (loss) on unsettled derivatives, net	10,040	(5,501)	) 6,094	(6,334)
Total revenues	\$35,453	\$16,188	\$74,656	\$58,023
Operating costs and expenses:				
Lease operating expenses	\$6,849	\$4,768	\$18,136	\$11,859
Oil and natural gas production taxes	\$1,845	\$1,007	\$4,694	\$2,670
Impairment of proved oil and natural gas properties	\$303	\$—	\$303	\$1,578
Depreciation, depletion and amortization	\$5,565	\$3,586	\$13,900	\$10,957
General and administrative (1)	\$2,602	\$1,630	\$11,958	\$9,667
Interest expense	\$1,226	\$895	\$3,087	\$2,320
Production:				
Oil (MBbls)	279	227	756	677
Natural gas (MMcf)	35	32	75	105
Total (MBoe)	285	232	769	694
Average net production (Boe/d)	3,098	2,522	2,817	2,542
Average sales price:				
Oil (per Bbl):				
Sales price	\$93.23	\$100.58	\$95.06	\$94.17
Effect of net settlements on commodity derivative instruments	\$(2.72)	) \$(5.70)	) \$(4.96)	) \$0.13
Realized oil price after derivatives	\$90.51	\$94.88	\$90.10	\$94.30
Natural gas (per Mcf):				
Sales price (2)	\$4.63	\$4.72	\$6.00	\$4.89
Average unit costs per Boe:				
Lease operating expenses	\$24.03	\$20.55	\$23.58	\$17.09
Oil and natural gas production taxes	\$6.47	\$4.34	\$6.10	\$3.85
Depreciation, depletion and amortization	\$19.53	\$15.46	\$18.08	\$15.79
General and administrative expenses	\$9.13	\$7.03	\$15.55	\$13.93

General and administrative expenses include non-cash, equity-based compensation of \$1.1 million and \$6.9 million (1) for the three and nine months ended September 30, 2014; and \$0.7 million and \$5.4 million for the three and nine months ended September 30, 2013, respectively.

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

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

Net income was approximately \$17.0 million for the three months ended September 30, 2014, compared to approximately \$4.3 million for the three months ended September 30, 2013, an increase of approximately \$12.7 million. The change was primarily attributable to the favorable net effect of our derivatives and an increase in oil sales from the acquisition of oil properties and production increases during 2014, partially offset by an increase in lease operating expenses, depreciation, depletion and amortization, and production taxes.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended September 30, 2014, were approximately \$26.2 million compared to approximately \$23.0 million for the three months ended September 30, 2013. The increase in revenues was primarily due to an increase in daily oil production resulting from incremental oil volumes from our acquisitions in 2014 and drilling and recompletion efforts in our Northeastern and Southern Oklahoma core areas.

On average, our production volumes for the three months ended September 30, 2014, were approximately 285 MBoe, or approximately 3,098 Boe per day on average. In comparison, our total production volumes for the three months ended September 30, 2013, were approximately 232 MBoe, or approximately 2,522 Boe per day on average. The increase in production volumes was primarily due to our acquisitions of additional oil properties in 2014 and drilling and recompletion efforts in our Northeastern and Southern Oklahoma core areas. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended September 30, 2014, was approximately \$93.23, compared with approximately \$100.58 for the three months ended September 30, 2013.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. To the extent the future commodity price outlook declines between measurement periods, we will have gains on our unsettled derivatives. To the extent future commodity price outlook increases between measurement periods, we will have losses on our unsettled derivatives. Due to the period change in the mark-to-market value of these contracts, we recorded a net gain of approximately \$9.3 million from our commodity hedging instruments for the three months ended September 30, 2014, which was composed of approximately \$10.0 million non-cash gain on unsettled derivative contracts, due to the decline in future commodity prices, and approximately \$0.7 million loss on net cash settlements of derivative contracts. For the three months ended September 30, 2013, we recorded a net loss from our commodity hedging instruments of approximately \$6.8 million, which was composed of a loss of approximately \$1.3 million on net cash settlements of derivative contracts and approximately \$5.5 million non-cash loss on unsettled derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately \$6.8 million for the three months ended September 30, 2014, or approximately \$24.03 per Boe, compared to approximately \$4.8 million for the three months ended September 30, 2013, or approximately \$20.55 per Boe. The increase in total lease operating expenses over the prior year's quarter was primarily attributable to our acquisitions of additional oil properties in 2014 and the additional number of producing wells resulting from our drilling and recompletion activities. The increase in average costs per Boe reflects higher costs of operations in our Hugoton Basin and Southern Oklahoma areas due to increased operating costs without the additional increase in production during the current period.

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 September 30, 2014, our production taxes were approximately \$1.8 million, or approximately \$6.47 per Boe for an effective tax rate of approximately 7.0%, compared to approximately \$1.0 million for the three months ended September 30, 2013, or approximately \$4.34 per Boe for an effective tax rate of approximately 4.4%. The increase in both production taxes and the rate per Boe during the three months ended September 30, 2014 was related to the expiration of a reduced production tax on a majority of our production that qualified for the Oklahoma Enhanced Recovery Project Gross Production Tax Exemption. The tax exemption was in effect for a majority of the production from our Southern Oklahoma properties for three months ended September 30, 2013. Also, the acquisition of additional properties during 2014 added to the increase in production taxes.

Impairment Expense. 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. For the three months ended September 30, 2014, we recorded approximately a \$0.3 million non-cash impairment charge for properties in our Southern Oklahoma core area due to reduced recoverable reserve estimates. There was no impairment charge for the three months ended September 30, 2013.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses ("DD&A") on producing properties for the three months ended September 30, 2014, were approximately \$5.6 million, or approximately \$19.53 per Boe produced, compared to approximately \$3.6 million, or approximately \$15.46 per Boe produced, for the three months ended September 30, 2013. The increase in DD&A was primarily due to the acquisition of oil properties in February

and August 2014. The increase in DD&A per Boe was primarily due to the higher depletion rates in the acquired properties compared to our legacy assets.

General and Administrative Expenses. Our general and administrative expenses were approximately \$2.6 million for the three months ended September 30, 2014, or approximately \$9.13 per Boe produced, compared to approximately \$1.6 million for the three months ended September 30, 2013 or approximately \$7.03 per Boe produced. The overall increase in general and administrative expenses for the three months ended September 30, 2014 was due to higher non-recurring legal and professional services related to the acquisition in August 2014 and the filing of our Registration Statement and related amendments and higher non-cash equity based compensation costs. Non-cash equity based compensation expense was \$1.1 million and \$0.7 million for the three months ended September 30, 2014 and 2013, respectively.

Interest Expense. Our interest expense for the three months ended September 30, 2014, was approximately \$1.2 million, compared to \$0.9 million for the three months ended September 30, 2013. The increase in interest expense during the three months ended September 30, 2014 compared to the three months ended September 30, 2013 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions in 2014.

Nine Months Ended September 30, 2014 Compared with the Nine Months Ended September 30, 2013

Net income was approximately \$22.4 million for the nine months ended September 30, 2014 compared to approximately \$18.9 million for the nine months ended September 30, 2013, an increase of approximately \$3.5 million. This increase primarily reflects the favorable net impact of changes in the mark-to-market fair value of our unsettled derivative contracts and an increase in oil production during the nine months ended September 30, 2014, partially offset by higher general and administrative expenses (including equity-based compensation expense), higher DD&A along with increased lease operating expenses.

Sales Revenues. Revenues from oil and natural gas sales for the nine months ended September 30, 2014 were approximately \$72.3 million as compared to approximately \$64.3 million for the nine months ended September 30, 2013. The increase in revenues was primarily due to an increase in daily oil production which includes incremental volumes from recent acquisitions.

Our production volumes for the nine months ended September 30, 2014 were approximately 769 MBoe, or approximately 2,817 Boe per day. In comparison, our total production volumes for the nine months ended September 30, 2013, were approximately 694 MBoe, or approximately 2,542 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 oil properties during 2014. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the nine months ended September 30, 2014 was \$95.06, compared with \$94.17 for the nine months ended September 30, 2013.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. To the extent the future commodity price outlook declines between measurement periods, we will have gains on our unsettled derivatives. To the extent future commodity price outlook increases between measurement periods, we will have losses on our unsettled derivatives. Due to the period change in the mark-to-market value of these contracts, we recorded a net gain of approximately \$2.3 million from our commodity hedging instruments for the nine months ended September 30, 2014, which was composed of approximately \$6.1 million non-cash gain on unsettled derivative contracts due to the decline in future commodity prices, and approximately \$3.8 million loss on net cash settlements of derivative contracts. For the nine months ended September 30, 2013, we recorded a net loss from our commodity hedging instruments of approximately \$6.2 million, which was composed of approximately \$6.3 million non-cash loss on unsettled derivative contracts and a \$0.1 million gain on net cash settlements of derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately \$18.1 million for the nine months ended September 30, 2014, or \$23.58 per Boe, compared to approximately \$11.9 million for the nine months ended

September 30, 2013, or approximately \$17.09 per Boe. The increase in total lease operating expenses and average costs per Boe was primarily attributable to the acquisition of additional oil properties in 2014, and the additional number of producing wells resulting from our drilling and recompletion programs. The increase in average costs per Boe reflects higher costs of operations in comparison to the proportional increases in production in our Hugoton Basin and Southern Oklahoma areas, which includes additional workover costs of approximately \$1.3 million, for the nine months ended September 30, 2014 as compared to nine months ended September 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 nine months ended September 30, 2014, our production taxes were

approximately \$4.7 million, or approximately \$6.10 per Boe for an effective tax rate of approximately 6.5%, compared to approximately \$2.7 million for the nine months ended September 30, 2013, or approximately \$3.85 per Boe for an effective tax rate of approximately 4.2%. The increase in both the production taxes and rate per Boe during the nine months ended September 30, 2014 was related to the expiration of a reduced production tax on a majority of our production that qualified for the Oklahoma Enhanced Recovery Project Gross Production Tax Exemption. The tax exemption was in effect for a majority of the production in our Southern Oklahoma properties during the nine months ended September 30, 2013. Also, the acquisition of additional properties during 2014 added to the increase in production taxes.

Impairment Expense. 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. For the nine months ended September 30, 2014, we recorded approximately a \$0.3 million non-cash impairment charge for properties in our Southern Oklahoma core area due to reduced recoverable reserve estimates. For the nine months ended September 30, 2013, we recorded approximately \$1.6 million non-cash impairment charge within our miscellaneous core area properties.

Depreciation, Depletion and Amortization Expenses. Our DD&A on producing properties for the nine months ended September 30, 2014, was approximately \$13.9 million, or approximately \$18.08 per Boe produced, compared to approximately \$11.0 million, or approximately \$15.79 per Boe produced, for the nine months ended September 30, 2013. The increase in DD&A was primarily due to the increase in total asset value of the oil and natural gas properties from the acquisition of additional oil properties in 2014. The increase in DD&A per Boe was primarily due to the higher depletion rates of the properties acquired in the Hugoton acquisition compared to our legacy assets.

General and Administrative Expenses. Our general and administrative expenses were approximately \$12.0 million for the nine months ended September 30, 2014, or approximately \$15.55 per Boe produced, compared to approximately \$9.7 million for the nine months ended September 30, 2013 or approximately \$13.93 per Boe produced. The overall increase in general and administrative expenses for the nine months ended September 30, 2014 was primarily due to an increase in compensation costs related to our non-cash equity based compensation plan in addition to higher non-recurring legal and professional services costs related to the acquisitions in 2014 and filing our registration statement and related amendments. Non-cash equity based compensation expense was \$6.9 million and \$5.4 million for the nine months ended September 30, 2014 and 2013, respectively.

Interest Expense. Our interest expense for the nine months ended September 30, 2014 was approximately \$3.1 million, compared to approximately \$2.3 million for the nine months ended September 30, 2013. The increase in interest expense during the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions in 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 September 30, 2014, consisted of approximately \$1.6 million of available cash, and \$22.0 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 and on August 29, 2014, the borrowing base was increased from \$170.0 million to \$190.0 million. No other material terms of the original credit agreement were amended.

As of September 30, 2014, our \$250.0 million revolving credit facility had a remaining borrowing capacity of \$22.0 million (\$190.0 million borrowing base less \$168.0 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):

	Nine Months Ended September 30,	
	2014	2013
Operating activities	\$39,580	\$42,485
Investing activities	(62,913)	(47,168)
Financing activities	23,469	4,289

Operating Activities. Net cash provided by operating activities was approximately \$39.6 million and \$42.5 million for the nine months ended September 30, 2014 and 2013, respectively. The \$2.9 million decrease from 2013 to 2014 was primarily attributable to higher lease operating expenses and production taxes offset by higher oil production. Our net cash provided by operating activities also includes an increase of \$2.7 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 \$62.9 million and approximately \$47.2 million for the nine months ended September 30, 2014 and 2013, respectively. Cash used in investing activities during the nine months ended September 30, 2014 included approximately \$38.8 million for the acquisition of oil properties and additional working interests. We also spent \$24.1 million on capital expenditures, primarily for drilling, development and completion activities. Cash used in investing activities during the nine months ended September 30, 2013 included approximately \$28.0 million for the acquisition of additional working interests. We also spent \$19.1 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 \$23.5 million and approximately \$4.3 million for the nine months ended September 30, 2014 and 2013, respectively. During the nine months ended September 30, 2014, cash provided by financing activities included net proceeds of approximately \$56.0 million from borrowings under our revolving credit facility which were used to

finance the acquisition of properties in 2014 and to develop capital projects. We also made cash distributions to our unitholders of approximately \$32.4 million. Cash provided by financing activities during the nine months ended September 30, 2013, included net proceeds from borrowings under our revolving credit facility of \$34.0 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 \$29.7 million.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size of our asset base. The primary purpose of growth capital is to acquire, develop and produce assets that allow us to increase our production levels and asset base. To date, we have funded acquisition transactions through a combination of cash, available borrowing capacity under our current revolving credit facility and the issuance of unregistered 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 \$9.4 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 September 30, 2014, we had approximately \$168.0 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 September 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.

On August 29, 2014, the borrowing base was increased from \$170.0 million to \$190.0 million. No other material terms of the original credit agreement were amended.

Borrowings under the facility may not exceed our current borrowing base of \$190.0 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 September 30, 2014, our open commodity derivative contracts were in a net asset position with a fair value of approximately \$4.7 million. All of our commodity derivative contracts are with major financial institutions. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments in the event of lower commodity prices and we could incur a loss. As of September 30, 2014, all of our counterparties had performed pursuant to their commodity derivative contracts.

All of our derivative contracts for 2014, 2015 and 2016 are composed of swaps with fixed settlements. Specifically for commodity price swap agreements, we agree to pay an adjustable or floating price tied to an agreed upon index for the commodity. 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 September 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 Form 10-Q and in our Annual Report.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil production. Realized pricing is primarily driven by the spot market prices applicable to the prevailing price for oil. Pricing for oil has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil production depend on many factors outside of our control, such as the strength of the global economy 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 at September 30, 2014, was a net asset of approximately \$4.7 million. A 10% change in oil prices with all other factors held constant would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity contracts of approximately \$8.5 million. Please see “Item 1. Financial Statements” contained herein for additional information.

Interest Rate Risk

At September 30, 2014, we had long-term debt outstanding of \$168.0 million, with an effective interest rate of approximately 2.8%. 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 \$0.4 million for the nine months. Our revolving credit facility allows borrowings up to \$190.0 million at an interest rate ranging from LIBOR plus a margin ranging from 1.75% to 2.75% or the prime rate plus a margin ranging from 0.75% to 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 September 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 September 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 August 11, 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).
10.4	Purchase and Sale Agreement, dated October 7, 2014, by and among Mid-Con Energy Properties, LLC, Mid-Con Energy Partners, LP and L.C.S. Production Company, SPA-PETCO, LP, SPA PETCO OSU, LLC, A.G. Hill Oil and Gas LP, and A.G. Hill Oil and Gas II 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 October 14, 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

November 3, 2014

By: /s/ Michael D. Peterson
Michael D. Peterson
Chief Financial Officer