Mid-Con Energy Partners, LP
Form 10-Q
November 02, 2015

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

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

For the quarterly period ended September 30, 2015

OR

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

Commission File No.: 1-35374

Mid-Con Energy Partners, LP
(Exact name of registrant as specified in its charter)

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

2501 North Harwood Street, Suite 2410
Dallas, Texas 75201
(Address of principal executive offices and zip code)
(972) 479-5980
(Registrant's telephone number, including area code)

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

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

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

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

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

As of November 2, 2015, the registrant had 29,725,356 limited partner units and 360,000 general partner units outstanding.

TABLE OF CONTENTS

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:

- future financial and operating results, and our ability to pay distributions;
- business strategies;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- revisions to oil and natural gas reserves estimates as a result of changes in commodity prices;
- volatility or continued low or further declining commodity prices;
- future capital requirements and availability of financing;
- technology;
- production volumes;
- lease operating expenses;
- general and administrative expenses;
- 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, 2014 (“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, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$961	$3,232
Accounts receivable:		
Oil and natural gas sales	6,192	8,051
Other	2,728	4,070
Derivative financial instruments	27,125	26,202
Prepaids and other	296	652
Total current assets	37,302	42,207
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, successful efforts method:		
Proved properties	511,861	501,191
Accumulated depletion, depreciation, amortization and impairment	(160,508)	(93,896)
Total property and equipment, net	351,353	407,295
DERIVATIVE FINANCIAL INSTRUMENTS	1,593	842
OTHER ASSETS	3,674	4,284
Total assets	$393,922	$454,628
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$2,982	$3,630
Related parties	910	3,989
Accrued liabilities	59	397
Total current liabilities	3,951	8,016
OTHER LONG-TERM LIABILITIES	107	107
LONG-TERM DEBT	194,000	205,000
ASSET RETIREMENT OBLIGATIONS	7,653	7,363
COMMITMENTS AND CONTINGENCIES		
EQUITY, per accompanying statements:		
Partnership equity:		
General partner interest	742	1,328
Limited partners- 29,726,289 and 29,166,112 units issued and outstanding as of September 30, 2015 and December 31, 2014, respectively.	187,469	232,814
Total equity	188,211	234,142
Total liabilities and equity	$393,922	$454,628

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,	
	2015	2014	2015	2014
Revenues:				
Oil sales	$18,137	$26,011	$56,675	$71,865
Natural gas sales	356	162	1,000	450
Gain on derivatives, net	19,771	9,280	12,544	2,341
Total revenues	38,264	35,453	70,219	74,656
Operating costs and expenses:				
Lease operating expenses	8,761	6,849	25,293	18,136
Oil and natural gas production taxes	206	1,845	2,634	4,694
Impairment of proved oil and natural gas properties	40,920	303	40,920	303
Depreciation, depletion and amortization	9,655	5,565	25,692	13,900
Accretion of discount on asset retirement obligations	91	64	276	175
General and administrative	2,253	2,602	7,531	11,958
Total operating costs and expenses	61,886	17,228	102,346	49,166
Income (loss) from operations	(23,622)	18,225	(32,127)	25,490
Other income (expense):				
Interest income and other	2	3	8	7
Interest expense	(1,804)	(1,226)	(5,361)	(3,087)
Loss on settlement of ARO	(54)	—	(54)	—
Total other expense	(1,856)	(1,223)	(5,407)	(3,080)
Net income (loss)	$(25,478)	$17,002	$(37,534)	$22,410
Computation of net income (loss) per limited partner unit:				
General partners’ interest in net income (loss)	$(306)	$268	$(451)	$375
Limited partners’ interest in net income (loss)	$(25,172)	$16,734	$(37,083)	$22,035
Net income (loss) per limited partner unit:				
Basic	$(0.85)	$0.75	$(1.25)	$1.04
Diluted	$(0.85)	$0.74	$(1.25)	$1.04
Weighted average limited partner units outstanding:				
Limited partner units (basic)	29,705	22,450	29,614	21,175
Limited partner units (diluted)	29,705	22,467	29,614	21,198

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,	
	2015	2014
Cash Flows from Operating Activities:		
Net income (loss)	$(37,534)	$22,410
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	25,692	13,900
Debt issuance costs amortization	839	144
Accretion of discount on asset retirement obligations	276	175
Impairment of proved oil and natural gas properties	40,920	303
Loss on settlement of ARO	54	—
Cash paid for settlement of ARO	(79)	—
Mark-to-market on derivatives:		
Gain on derivatives, net	(12,544)	(2,341)
Cash settlements received (paid) for matured derivatives, net	15,566	(3,753)
Cash settlements received from early termination and modification of derivatives, net	11,069	—
Cash premiums paid for derivatives, net	(15,765)	—
Non-cash equity-based compensation	2,957	6,900
Changes in operating assets and liabilities:		
Accounts receivable	1,859	(1,717)
Other receivables	1,342	(118)
Prepaids and other	128	(95)
Accounts payable and accrued liabilities	(3,446)	3,772
Net cash provided by operating activities	31,334	39,580
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(11,250)	(24,079)
Acquisitions of oil and natural gas properties	(1)	(38,834)
Net cash used in investing activities	(11,251)	(62,913)
Cash Flows from Financing Activities:		
Proceeds from line of credit	28,000	109,000
Payments on line of credit	(39,000)	(53,000)
Offering costs	(88)	—
Distributions paid	(11,266)	(32,361)
Debt issuance costs	—	(170)
Net cash (used in) provided by financing activities	(22,354)	23,469
Net (decrease) increase in cash and cash equivalents	(2,271)	136
Beginning cash and cash equivalents	3,232	1,434
Ending cash and cash equivalents	$961	$1,570
Supplemental Cash Flow Information:		
Cash paid for interest	$4,606	$3,156
Non-Cash Investing and Financing Activities:		
Accrued capital expenditures - oil and natural gas properties	$658	$1,043
Common 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	Limited Partner Amount	Total Equity
Balance, December 31, 2014	$1,328	29,166	$232,814	$234,142
Equity-based compensation	—	560	2,957	2,957
Offering costs	—	—	(88)	(88)
Distributions	(135)	—	(11,131)	(11,266)
Net loss	(451)	—	(37,083)	(37,534)
Balance, September 30, 2015	$742	29,726	$187,469	$188,211

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 ownership, 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 ("common units") are traded on the National Association of Securities Dealers Automated Quotation System Global Select Market ("NASDAQ") under the symbol “MCEP”.
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, 2014 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, 2014.
All intercompany transactions and account balances have been eliminated.
Reclassifications
The condensed consolidated financial statements for previous periods include certain reclassifications to the derivative accounts that were made to conform to current presentation. Such reclassifications have no impact on previously reported total assets, net income (loss) or total operating cash flows.
Note 2. Acquisitions
Acquisitions 2014

The following acquisitions were accounted for under the acquisition method of accounting. Accordingly, we conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition dates, while transaction and integration costs associated with the acquisitions were expensed as incurred. The results of all acquisitions have been included in the consolidated financial statements since the acquisition dates.

Eastern Shelf acquisition

During November 2014, we acquired multiple oil properties located in Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall, Taylor, and Tom Green Counties, Texas ("Eastern Shelf") for an aggregate purchase price of approximately $117.6 million, subject to customary post-closing purchase price adjustments. The transaction was primarily funded with borrowings under our revolving credit facility of approximately $21.6 million in cash and the issuance of 5,800,000 common units having an approximate value of $96.0 million, net of offering costs. The recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets:	
Oil properties	$119,438
Total assets acquired	$119,438
Fair value of net liabilities assumed:	
Asset retirement obligation	1,851
Fair value of net assets acquired	$117,587

Oilton acquisition

During August 2014, we acquired from our affiliate, Mid-Con Energy III, LLC, a certain oil property located in Creek County, Oklahoma ("Oilton") for an aggregate purchase price of approximately $56.5 million. 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 common units having an approximate value of $52.0 million.

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

Fair Value of net assets:	
Oil property	$56,979
Total assets acquired	$56,979
Fair Value of net liabilities assumed:	
Asset retirement obligation	479
Net assets acquired	$56,500

Liberty South acquisition

During August 2014, we acquired a waterflood unit in Liberty County, Texas ("Liberty South") for approximately $18.9 million. 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 an aggregate purchase price of approximately $7.3 million. 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 purchase price of approximately $41.0 million. The transaction was primarily funded with borrowings under our revolving credit facility of approximately $7.0 million and the issuance of 1,500,000 common units having an approximate value of $34.0 million. The recognized fair values of the assets 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

Note 3. Equity Awards

We have a long-term incentive program (the “Long-Term Incentive Program”) for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, LLC (“Mid-Con Energy Operating”), who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, 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, 2015:

	Number of Common Units
Approved and authorized awards	1,764,000
Unrestricted units granted	(1,113,374)
Restricted units granted, net of forfeitures	(435,256)
Equity-settled phantom units, net of forfeitures	(100,500)
Phantom units issued, net of forfeitures	(22,166)
Awards available for future grant	92,704

We recognized $0.6 million and $3.0 million of total equity-based compensation expense for the three and nine months ended September 30, 2015, respectively, and for the three and nine months ended September 30, 2014 we recognized $1.1 million and $7.1 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.

Restricted awards

We account for restricted units as equity awards since these awards will be settled by issuing common units. These restricted units generally 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, 2015 is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	109,800	$23.28
Units granted	294,100	$5.42
Units vested	(148,195)	$12.43
Units forfeited	(31,473)	$9.07
Outstanding at September 30, 2015	224,232	$9.02

During the nine months ended September 30, 2015, we granted 274,550 unrestricted and 268,000 restricted common units with one-third vesting immediately and the other two-thirds vesting over two years, and 26,100 restricted common units with a three-year vesting period.

As of September 30, 2015, there was approximately $1.3 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 1.3 years.

Equity-settled phantom awards

In July 2015, we granted 69,000 equity-settled phantom units with one-third vesting immediately and the other two thirds vesting over two-years, and 46,500 equity-settled phantom units with a three-year vesting period. The equity-settled phantom units do not have any rights or privileges of a unitholder, including right to distributions, until vesting and the resulting conversion into common units. These units were granted to certain employees of our affiliates and certain directors and founders of our general partner. We account for equity-settled phantom units as equity awards since these awards will be settled by issuing common units and we assume a 10% forfeiture rate. The costs associated with the equity-settled phantom units are reported as a component of general and administrative expense in our unaudited condensed consolidated statement of operations. For the three and nine months ended September 30, 2015 we recorded approximately $24,000 of compensation expense. Activity related to these units is as follows:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	—	—
Units granted	115,500	$3.27
Units vested	(23,000)	$3.27
Units forfeited	(15,000)	$3.27
Outstanding at September 30, 2015	77,500	$3.27

As of September 30, 2015, there was approximately $0.2 million of unrecognized compensation costs related to equity-settled phantom units. The cost is expected to be recognized over a weighted average period of approximately 2.2 years.

Note 4. Derivative Financial Instruments

The objective of our risk management program is to achieve more predictable cash flows by reducing our exposure to short-term fluctuations in the price of oil and natural gas. We believe this strategy will serve to secure a baseline portion of our revenues and, by retaining some opportunity to participate in upward price movements, may also enable us to realize higher revenues during periods when prices rise.

To this end, we utilize financial derivatives-namely swaps, calls and puts-to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts and/or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so.

At September 30, 2015, our open positions consisted of crude oil price swaps and collars consisting of long puts and short calls with the same strike price. 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. With the collars having the same strike prices, they settle like a swap.

Each call transaction has an established fixed price. When the settlement price is above the fixed price, we pay the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract volume. If the settlement price is below the fixed price, the call option expires.

Each put transaction has an established fixed price. The counterparty charges a premium in order to enter into the put transactions. These premiums are deferred and will be paid monthly as the contracts settle. If the floating price is below the floor price, we receive from the counterparty an amount equal to the difference multiplied by the contract volume net of the deferred premium we owe upon contract settlement. If the floating price exceeds the fixed price, the put option expires, and we pay the deferred premium.

We have elected not to designate commodity derivative 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. 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. 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. At September 30, 2015 and December 31, 2014, we recorded the estimated fair value of the derivative contracts as a net asset of $28.7 million and $27.0 million, respectively.

As of September 30, 2015, we had the following oil derivative open positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day
Swaps - 2015	$90.24			2,935
Swaps - 2016	$84.11			1,434
Collars - 2016		$50.00	$50.00	1,107

During the first quarter of 2015, we restructured a significant portion of our existing oil derivatives that were in place at December 31, 2014. This resulted in the early settlement of certain contracts existing at December 31, 2014, and entering into new oil derivative contracts which extend through September 2016. In connection with the early termination and modifications of our commodity derivative contracts, we received net proceeds of approximately $11.1 million from the early termination of contracts at January 31, 2015, received approximately $5.9 million from selling calls and paid out approximately $19.8 million in premiums to extend the contracts through September 2016. The restructuring also resulted in approximately $4.1 million in deferred put options. As of September 30, 2015, we had paid $1.9 million of the deferred put premiums in connection with contract 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. As of September 30, 2015, the counterparties to our derivative contracts currently in place are lenders under our revolving credit facility and have investment grade credit ratings.

The following tables 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, 2015 and December 31, 2014 (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, 2015:			
Assets			
Derivative financial instruments - current asset	$31,244	$(4,119)	$27,125
Derivative financial instruments - long-term asset	1,593	—	1,593
Total	$32,837	$(4,119)	$28,718
Liabilities			
Derivative financial instruments - current liability	$(1,992)	$1,992	$—
Derivative deferred premium - current liability	(2,127)	2,127	—
Derivative financial instruments - long-term liability	—	—	—
Derivative deferred premium - long-term liability	—	—	—
Total	$(4,119)	$4,119	$—
Net Asset	$28,718	$—	$28,718

	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, 2014:			
Assets			
Derivative financial instruments - current asset	$26,202	$—	$26,202
Derivative financial instruments - long-term asset	842	—	842
Total	$27,044	$—	$27,044
Liabilities			
Derivative financial instruments - current liability	$—	$—	$—
Derivative financial instruments - long-term liability	—	—	—
Total	$—	$—	$—
Net Asset	$27,044	$—	$27,044

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net settlements on matured derivatives	$8,383	$(760)	$15,566	$(3,753)
Net settlements on early terminations and modifications of derivatives	—	—	11,069	—
Change in fair value of unsettled derivatives, net	11,388	10,040	(14,091)	6,094
Total gain on derivatives, net	$19,771	$9,280	$12,544	$2,341

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 New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") 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.

14

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 and their corresponding deferred premiums 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 our counterparties and third-party providers 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, for instance when there are declines in commodity prices or well performance. 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. We calculate the estimated fair values using valuation techniques consistent with the income approach, converting future cash flow to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flow is the product of a process that begins with NYMEX WTI forward curve pricing (Level 1), as well as Level 3 assumptions including: pricing adjustments for estimated location and quality differentials, production costs, capital expenditures, production volumes and estimated reserves.

During the three and nine months ended September 30, 2015, we recorded a non-cash impairment charge of approximately $40.9 million associated with proved oil and natural gas properties throughout our core areas reducing the carrying value of certain properties from $392.3 million to their fair value of $351.4 million. The impairment was primarily due to a continued decline in commodity prices and to a lesser degree, reduced reserve estimates. The impairment charges are included in “Impairment of proved oil and natural gas properties" in our unaudited condensed consolidated statements of operations. In late 2014, prices for oil, natural gas and NGLs declined precipitously. Prices have continued to remain low through September 2015, while forward NYMEX WTI price curves have declined year-to-date. In the future, if forward price curves continue to decline, the Partnership may have additional impairments which could have a material impact on its results of operations. During the three and nine months ended September 30, 2014, we recorded a non-cash impairment charge of approximately $0.3 million 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, 2015 and December 31, 2014 (in thousands):

	Level 1	Level 2	Level 3	Fair Value
September 30, 2015				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments- asset	$—	$32,837	$—	$32,837
Derivative financial instruments- liability	—	(1,992)	—	(1,992)
Derivative deferred premiums - liability	—	—	(2,127)	(2,127)
Net financial assets	$—	$30,845	$(2,127)	$28,718
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$—	$—	$14	$14
Impairment of proved oil and natural gas properties	$—	$—	$40,920	$40,920
December 31, 2014				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments- asset	$—	$27,044	$—	$27,044
Derivative financial instruments- liability	—	—	—	—
Net financial assets	$—	$27,044	$—	$27,044
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$—	$—	$3,171	$3,171
Impairment of proved oil and natural gas properties	$—	$—	$30,206	$30,206

A summary of the changes in Level 3 fair value measurements for the periods presented are as follows:

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014
	(in thousands)	
Balance of Level 3 at beginning of period	$—	$—
Derivative deferred premiums - purchases	(4,068)	—
Derivative deferred premiums - settlements	1,941	—
Balance of Level 3 at end of period	$(2,127)	$—

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, 2015 and 2014.

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 oil and natural gas 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.

AROs 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 unaudited condensed consolidated statement of operations. The discounted capitalized cost is amortized to expense through the depreciation calculation over the life of the assets based on proved developed reserves.

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

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014
	(in thousands)	
Asset retirement obligation - beginning of period	$7,363	$3,942
Liabilities incurred for new wells and interest	26	3,171
Liabilities settled upon plugging and abandoning wells	(25)	—
Revision of estimates	13	—
Accretion expense	276	250
Asset retirement obligation - end of period	$7,653	$7,363

As of September 30, 2015 and December 31, 2014, 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, 2015, 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 $220.0 million as determined at April 2, 2015.

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, 2015, we had $194.0 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, 2015, the average effective interest rate was approximately 2.95%. 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.

During February 2015, the revolving credit facility was amended to allow our EBITDAX calculation, as defined in section 7.13 of the original revolving credit agreement, to reflect the net cash flows attributable to the restructured commodity derivative contracts that occurred during January 2015 to be recognized in specific amounts for the periods of the first quarter 2015 through the third quarter of 2016.

Redetermination of the borrowing base under the revolving credit facility, based primarily on reserve reports using lender forward price curve estimates for oil and natural gas at such time, occurs semi-annually, in approximately April and October of each year, with an additional optional 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 April 2015 borrowing base redetermination, our borrowing base was reduced to $220.0 million from $240.0 million as a result of lower commodity prices. The continuation of low commodity prices and/or declining forward price curve estimates, reductions in our capital budget and resulting reserve write-downs, are likely to result in additional decreases in the borrowing base during our Fall 2015 redetermination and may also impact future redeterminations. We initiated our Fall 2015 borrowing base redetermination in October 2015 and expect to finalize this process in late November. We do expect that our borrowing base will be reduced as a result of continued declines in oil and natural gas prices, however, the precise amount of the reduction is not known at this time.

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, 2015.

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 and our General Counsel, 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 the following named employees of our general partner: Jeffrey R. Olmstead, President and Chief Executive Officer; and Charles R. Olmstead, Executive Chairman of the Board of our general partner. The previous employment agreement with S. Craig George was terminated in August 2014. 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. 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 $0.8 million to $1.4 million, including the value of vesting of any outstanding units.

Note 9. Equity

Common Units

At September 30, 2015 and December 31, 2014, the Partnership’s equity consisted of 29,726,289 and 29,166,112 common units, respectively, representing approximately a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement (the “Agreement”) to sell, from time to time through or to the Managers (as defined in the Agreement), up to $50.0 million in common units representing limited partner interests. The sales, if any, of common units made under the Agreement will be made by any method permitted by law deemed to be an "at-the-market-offering" as defined in Rule 415 under the Securities Act of 1933, as amended (the "Securities Act"), including without limitation, sales made directly on the NASDAQ, on any other existing trading market for our common units or to or through a market maker. From the period of the original agreement, we did not sell any common units.

Cash Distributions

Our partnership agreement requires us to distribute all of our available cash on a quarterly basis. Our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs, including cash from working capital borrowings. There is no assurance as to future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors. Our revolving credit facility prohibits us from making cash distributions if any potential default or event of default, as defined in our revolving credit facility, occurs or would result from the cash distribution.

On October 21, 2015, the Board of Directors elected to suspend the quarterly cash distribution for the third quarter of 2015 and reserve the approximately $3.8 million in cash from current distributions. Prolonged declines in commodity prices prompted us to suspend distributions in an effort to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. See Note 12 Subsequent Events for further details.

The following sets forth the distributions we paid during the nine months ended September 30, 2015 (in thousands, except per unit distribution):

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 13, 2015	October 1, 2014 - December 31, 2014	$0.125	$3,752
May 14, 2015	January 1, 2015 - March 31, 2015	$0.125	$3,752
August 13, 2015	April 1, 2015 - June 30, 2015	$0.125	$3,762

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, 2015, we reimbursed Mid-Con Energy Operating approximately $1.0 million and $2.7 million, for direct expenses, respectively. These costs are included in the general and administrative expenses in our unaudited condensed consolidated statements of operations.

Other Transactions with Related Persons

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies, or COPAS, fee). We and those third parties will also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements.

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. See Note 2 to the Unaudited Condensed Consolidated Financial Statements for more information regarding these acquisitions.

At September 30, 2015, we had payables to Mid-Con Energy Operating of approximately $0.9 million which was comprised of a joint interest billing payable of approximately $0.6 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, 2017 and is to be applied retrospectively. Early adoption is permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures.
In February 2015, the Financial Accounting Standards Board issued Accounting Standards Update No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which provides guidance on the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities such as limited partnerships, limited liability corporations, and securitization structures (collateralized debt obligations, collateralized loan obligations, and mortgage-backed security transactions). In addition to reducing the number of consolidation models from four to two, the guidance simplifies and improves current guidance by placing more emphasis on risk of loss when determining a controlling financial interest and reducing the frequency of the application of related-party guidance when determining a controlling financial interest in a VIE. The standard is effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period, with early adoption permitted. We are currently evaluating the effect, if any, that this new guidance will have on our consolidated financial statements and related disclosures.
In April 2015, the Financial Accounting Board issued Accounting Standards Update No. 2015-03, Interest: Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The update requires debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of being presented as an asset. Debt disclosures will include the face amount of the debt liability and the effective interest rate. The update requires retrospective application and represents a change in accounting principle. The update is effective for annual reporting periods beginning after December 15, 2015, with early adoption permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures.
Note 12. Subsequent Events
Proxy
On October 12, 2015, the Partnership announced that it has filed a definitive proxy statement with the SEC regarding the approval of a proposal to amend (the "Amendment") the Partnership's Long-Term Incentive Program ("LTIP") and has set the date of a special meeting of its unitholders to approve the transaction. The Partnership's special meeting of unitholders will be held on November 20, 2015 at 9:00 a.m., local time, at MCEP’s offices at 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201.
Awards under the LTIP are currently limited to 1,764,000 units. As of October 9, 2015, approximately 92,704 common units remained available for future issuance to participants under the LTIP. Subject to adjustment for certain events, the Amendment increases the number of common units that may be granted for any and all awards by 1,750,000 common units to a total of 3,514,000 common units. After such increase, 1,842,704 common units will be available for future issuance under the LTIP. See our Form 14-A filed with the SEC on October 13, 2015 for further details.
Distributions
On October 21, 2015, the Board of Directors elected to suspend the quarterly cash distribution for the third quarter of 2015 and reserve the approximately $3.8 million in cash from current distributions. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining a future distribution. The suspension of cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders

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

Mid-Con Energy Partners, LP ("we," "our," "us," the "Partnership") is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, 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 ("common units") are traded on the NASDAQ under the symbol "MCEP".

Our properties are located primarily in the Mid-Continent and Permian Basin regions of the United States in five core areas: Southern Oklahoma, Northeastern Oklahoma, parts of Oklahoma, Colorado and Texas within the Hugoton, Texas Gulf Coast and Texas within the Eastern Shelf of the Permian ("Permian"). 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 Events

Cash Distributions

On August 13, 2015, we paid a cash distribution to unitholders for the second quarter of 2015 at a rate of $0.125 per unit. The aggregate amount of the distribution was approximately $3.8 million.

Commodity Prices

Our revenues and net income are sensitive to oil and natural gas prices which have been and are expected to continue to be highly volatile. In the third quarter of 2015, the NYMEX WTI spot price averaged approximately $46 per barrel, compared with approximately $97 per barrel in the third quarter of 2014. For the nine months ended September 30, 2015, the NYMEX WTI spot price averaged approximately $51 per barrel, compared with approximately $100 per barrel in the same period of 2014.

Sustained low oil and natural gas prices could have a significant impact on the carrying value of our oil and natural gas properties as well as the volumes and corresponding revenues of our estimated proved oil and natural gas reserves. To quantify the impact of lower oil and natural gas prices, we provide the following examples. If the commodity prices used to calculate fair value for each of our oil and natural gas properties were reduced by 5% or 10%, we estimate the incremental non- cash impairment charges would approximate $4.0 million and $39.0 million, respectively. If year-ended 2014 estimated proven reserves were recalculated based on a 12-month trailing average oil price at September 30, 2015, estimated proven reserve volumes and future net revenues would respectively decline 13.8% and 47.0%.

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. In late 2014, prices for oil, natural gas and NGLs declined precipitously, and prices have remained low through September 2015; prices for oil have remained at or below $62 per Bbl and natural gas prices have remained below $3.25 per MmBtu.

The objective of our risk management program is to achieve more predictable cash flows by reducing our exposure to short-term fluctuations in the price of oil and natural gas. We believe this strategy will serve to secure a baseline portion of our revenues and, by retaining some opportunity to participate in upward price movements, may also enable us to realize higher revenues during periods when prices rise. To this end, we utilize commodity derivatives-namely swaps, calls and puts-to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts and/or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so. We conduct our risk management activities exclusively with participant lenders in our revolving credit facility.

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 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,	
	2015	2014	2015	2014
Revenues:				
Oil sales	$18,137	$26,011	$56,675	$71,865
Natural gas sales	356	162	1,000	450
Gain on derivatives, net	19,771	9,280	12,544	2,341
Total revenues	$38,264	$35,453	$70,219	$74,656
Operating costs and expenses:				
Lease operating expenses	$8,761	$6,849	$25,293	$18,136
Oil and natural gas production taxes	$206	$1,845	$2,634	$4,694
Impairment of proved oil and natural gas properties	$40,920	$303	$40,920	$303
Depreciation, depletion and amortization	$9,655	$5,565	$25,692	$13,900
General and administrative (1)	$2,253	$2,602	$7,531	$11,958
Interest expense	$1,804	$1,226	$5,361	$3,087
Production:				
Oil (MBbls)	422	279	1,210	756
Natural gas (MMcf)	151	35	417	75
Total (MBoe)	447	285	1,279	769
Average net production (Boe/d)	4,859	3,098	4,685	2,817
Average sales price:				
Oil (per Bbl):				
Sales price	$42.98	$93.23	$46.84	$95.06
Effect of net settlements on matured derivative instruments (2)	$19.84	$(2.72)	$12.42	$(4.96)
Realized oil price after derivatives	$62.82	$90.51	$59.26	$90.10
Natural gas (per Mcf):				
Sales price (3)	$2.36	$4.63	$2.40	$6.00
Average unit costs per Boe:				
Lease operating expenses	$19.60	$24.03	$19.78	$23.58
Oil and natural gas production taxes	$0.46	$6.47	$2.06	$6.10
Depreciation, depletion and amortization	$21.60	$19.53	$20.09	$18.08
General and administrative expenses	$5.04	$9.13	$5.89	$15.55

(1) General and administrative expenses include non-cash equity-based compensation of $0.6 million and $3.0 million for the three and nine months ended September 30, 2015; and $1.1 million and $6.9 million for the three and nine months ended September 30, 2014, respectively.

(2) Effects on net settlements on commodity derivative instruments does not include the $11.1 million received from restructuring the previous oil derivative contracts in January 2015.

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

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014

We reported net loss of approximately $25.5 million for the three months ended September 30, 2015, compared to net income of approximately $17.0 million for the three months ended September 30, 2014, a decrease of approximately $42.5 million. The change was primarily attributable to lower oil sales prices, higher impairment charges, higher depreciation, depletion and amortization ("DD&A") expense, and higher lease operating expenses partially offset by the favorable net effect of our derivatives along with lower production taxes for the three months ended September 30, 2015.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended September 30, 2015, were approximately $18.5 million compared to approximately $26.2 million for the three months ended September 30, 2014. Despite the year over year production growth resulting from incremental volumes from acquisitions of properties in 2014, revenues were negatively affected by lower oil and gas prices. In the third quarter of 2015, the NYMEX WTI spot price averaged approximately $46 per barrel, compared with approximately $97 per barrel in the third quarter of 2014. During the three months ended September 30, 2015, the NYMEX WTI spot price ranged from a low of approximately $38 per barrel to a high of approximately $57 per barrel. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended September 30, 2015 was approximately $42.98, compared to approximately $93.23 for the three months ended September 30, 2014.

On average, our production volumes for the three months ended September 30, 2015, were approximately 447 MBoe, or approximately 4,859 Boe per day on average. In comparison, our total production volumes for the three months ended September 30, 2014, were approximately 285 MBoe, or approximately 3,098 Boe per day on average. The 57% year-over-year increase in production volumes was primarily attributable to acquisitions of additional oil properties in 2014 and successful development activities in the Permian and Northeastern Oklahoma core areas, as well as positive waterflood responses at Hugoton.

Effects of Commodity Derivative Contracts. We utilize NYMEX WTI 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. During the three months ended September 30, 2015, we recorded a net gain of approximately $19.8 million which was composed of approximately $11.4 million non-cash gain on changes in fair value of unsettled derivative contracts and approximately a $8.4 million gain on net cash settlements of derivative contracts. For the three months ended September 30, 2014, we recorded a net gain from our commodity hedging instruments of approximately $9.3 million, which was composed of approximately $10.0 million non-cash gain on changes in fair value of unsettled derivative contracts and approximately $0.7 million loss on net cash settlements of derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $8.8 million for the three months ended September 30, 2015, or approximately $19.60 per Boe, compared to approximately $6.8 million for the three months ended September 30, 2014, or approximately $24.03 per Boe. The increase in total lease operating expenses was primarily attributable to the acquisitions of additional oil properties in 2014 and the additional number of producing wells resulting from our drilling and recompletion programs. The decrease in average costs per Boe reflects the impact of the 2014 Permian acquisition which had and continues to have a significantly lower LOE/Boe profile.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas sales revenues and exclude the effects of our commodity derivative contracts. For the three months ended September 30, 2015, our production taxes were approximately $0.2 million, or approximately $0.46 per Boe for an effective tax rate of approximately 1.1%, compared to approximately $1.8 million for the three months ended September 30, 2014, or approximately $6.47 per Boe for an effective tax rate of approximately 7.0%. The decrease in production taxes was attributable to lower oil and natural gas revenues driven by lower prices and to the approval by the Oklahoma Tax Commission of an Enhanced Oil Recovery Production Tax Exemption ("EOR exemption") for one of our Northeastern Oklahoma units. Based on a effective date of April 2013, the Partnership recouped approximately $0.8 million in cash production taxes previously paid. The EOR exemption will extend through March 2018. The decrease in production tax per Boe was primarily attributable to the 2014 acquisitions of properties in Texas that have a lower production tax rate as compared to our legacy properties in Oklahoma and to the effect of the EOR exemption.

Excluding the effect of the amounts recouped from the EOR exemption that were attributable to prior periods, the effective tax rate for the third quarter of 2015 would have been 5.5%.

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, 2015, we recorded approximately a $40.9 million non-cash impairment charge primarily in our Hugoton core area, Gulf Coast core area and also in our Permian core area due to a continued decline in commodity prices and to a lesser degree, reduced reserve estimates. For the three months ended September 30, 2014, we recorded a non-cash impairment charge of $0.3 million for properties in our Southern Oklahoma core area due to reduced recoverable reserve estimates.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses (“DD&A”) on producing properties for the three months ended September 30, 2015, were approximately $9.7 million, or approximately $21.60 per Boe produced, compared to approximately $5.6 million, or approximately $19.53 per Boe produced, for the three months ended September 30, 2014. The increase in DD&A was primarily due to the increase in the total asset value of our oil and natural gas properties resulting from the acquisitions of additional oil properties in 2014. The increase in DD&A per Boe was due to higher depletion rates in some of the oil and gas properties acquired in 2014.

General and Administrative Expenses. Our general and administrative expenses ("G&A") were approximately $2.3 million for the three months ended September 30, 2015, or approximately $5.04 per Boe produced, compared to approximately $2.6 million for the three months ended September 30, 2014, or approximately $9.13 per Boe produced. The decrease in G&A expenses for the three months ended September 30, 2015 was attributed to lower compensation costs related to our non-cash equity-based compensation plan, resulting principally from the lower price of our common units, and to non-recurring legal and professional service costs. The decrease in G&A reflects the Partnership's efforts to focus on our production and development activities while containing administrative costs. G&A included non-cash equity based compensation of approximately $0.6 million and approximately $1.1 million for the three months ended September 30, 2015 and 2014, respectively.

Interest Expense. Our interest expense for the three months ended September 30, 2015, was approximately $1.8 million, compared to approximately $1.2 million for the three months ended September 30, 2014. The increase in interest expense during the three months ended September 30, 2015 was attributable to the higher borrowings outstanding from our revolving credit facility resulting from acquisitions of oil properties in November 2014.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014

We reported a net loss of approximately $37.5 million for the nine months ended September 30, 2015, compared to net income of approximately $22.4 million for the nine months ended September 30, 2014, a decrease of approximately $59.9 million. This decrease primarily reflects the negative impact of lower oil and gas prices along with higher impairment charges, higher DD&A , higher lease operating expenses, and higher interest expense, partially offset by the favorable net effect of our derivatives along with lower G&A and lower production taxes during the nine months ended September 30, 2015.

Sales Revenues. Revenues from oil and natural gas sales for the nine months ended September 30, 2015, were approximately $57.7 million as compared to approximately $72.3 million for the nine months ended September 30, 2014. Despite the year over year production growth resulting from incremental volumes from acquisitions of properties in 2014, revenues were negatively affected by lower oil and gas prices. For the nine months ended September 30, 2015, the NYMEX WTI spot price averaged approximately $51 per barrel, compared with approximately $100 per barrel in the same period of 2014. In 2015, the NYMEX WTI spot price ranged from a low of approximately $38 per barrel to a high of approximately $61 per barrel. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the nine months ended September 30, 2015 was $46.84, compared with $95.06 for the nine months ended September 30, 2014.

Our production volumes for the nine months ended September 30, 2015 were approximately 1,279 MBoe, or approximately 4,685 Boe per day. In comparison, our total production volumes for the nine months ended September 30, 2014, were approximately 769 MBoe, or approximately 2,817 Boe per day. The increase in production volumes was primarily due to acquisitions of additional oil properties in 2014 and drilling and recompletion efforts in our Northeastern Oklahoma and Permian core areas.

Effects of Commodity Derivative Contracts. We utilize NYMEX WTI 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. During the nine months ended September 30, 2015, we recorded a net gain of approximately $12.5 million which was composed of approximately $26.6 million gain on net cash settlements of derivative contracts and approximately $14.1 million non-cash loss on changes in fair value of unsettled derivative contracts. The net cash settlements consist of approximately $11.1 million for the early termination of our contracts in place and approximately $15.5 million from settled derivatives in place during the nine months ended September 30, 2015. The unrealized loss of approximately $14.1 million included the $11.1 million gain from early termination of the contracts and the $3.6 million gain upon settlements in January 2015 for contracts that were not early terminated or modified, both of which were previously recognized in the results of operations during the year ended December 31, 2014. For the nine months ended September 30, 2014, we recorded a net gain from our commodity hedging instruments of approximately $2.3 million, which was composed of approximately $6.1 million non-cash gain on changes in fair value of unsettled derivative contracts and approximately $3.8 million loss on net cash settlements of derivative contracts.

Lease Operating Expenses. Our lease operating expenses were approximately $25.3 million for the nine months ended September 30, 2015, or approximately $19.78 per Boe, compared to approximately $18.1 million for the nine months ended September 30, 2014, or approximately $23.58 per Boe. The increase in total lease operating expenses 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 decrease in average costs per Boe reflects the impact of the 2014 Permian acquisition which had a significantly lower LOE/Boe profile.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas sales revenues and exclude the effects of our commodity derivative contracts. For the nine months ended September 30, 2015, our production taxes were approximately $2.6 million, or approximately $2.06 per Boe for an effective tax rate of approximately 4.6%, compared to approximately $4.7 million for the nine months ended September 30, 2014, or approximately $6.10 per Boe for an effective tax rate of approximately 6.5%. The decrease in production taxes during the nine months ended September 30, 2015 was attributable to lower oil and natural gas revenues driven by lower prices and to the approval by the Oklahoma Tax Commission of an EOR Production Tax Exemption for one of our Northeastern Oklahoma units. Based on a effective date of April 2013, the Partnership recouped approximately $0.8 million in cash production taxes previously paid. The EOR exemption will extend through March 2018. The decrease in production tax per Boe was primarily attributable to the 2014 acquisitions of properties in Texas that have a lower production tax rate as compared to our legacy properties in Oklahoma and to the effect of the EOR exemption. Excluding the effect of the amounts recouped from the EOR exemption that were attributable to prior periods, the effective tax rate for the nine months ended September 30, 2015 would have been 6.0%.

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, 2015, we recorded approximately a $40.9 million non-cash impairment charge primarily in our Hugoton core area, Gulf Coast core area and also in our Permian core area due to a continued decline in commodity prices and to a lesser degree, reduced reserve estimates. For the nine months ended September 30, 2014, we recorded a non-cash impairment charge of $0.3 million non-cash impairment charge for properties in our Southern Oklahoma core area due to reduced recoverable reserve estimates.

Depreciation, Depletion and Amortization Expenses. Our DD&A on producing properties for the nine months ended September 30, 2015, was approximately $25.7 million, or approximately $20.09 per Boe produced, compared to approximately $13.9 million, or approximately $18.08 per Boe produced, for the nine months ended September 30, 2014. The increase in DD&A was primarily due to the increase in the total asset value of our oil and natural gas properties after acquisitions of additional oil properties in 2014. The increase in DD&A per Boe was due to higher depletion rates in some of the oil and gas properties acquired in 2014.

General and Administrative Expenses. Our G&A expenses were approximately $7.5 million for the nine months ended September 30, 2015, or approximately $5.89 per Boe produced, compared to approximately $12.0 million for the nine months ended September 30, 2014 or approximately $15.55 per Boe produced. The overall decrease in G&A expenses for the nine months ended September 30, 2015 was attributed to lower compensation costs related to our non-cash equity-based compensation plan, resulting principally from the lower price of our common units, and to lower legal and professional services which were necessary in 2014 to comply with public reporting filings associated with our acquisitions of oil and natural gas properties. Non-cash equity-based compensation was approximately $3.0

million and approximately $6.9 million for the nine months ended September 30, 2015 and 2014, respectively.

Interest Expense. Our interest expense for the nine months ended September 30, 2015 was approximately $5.4 million, compared to approximately $3.1 million for the nine months ended September 30, 2014. The increase in interest expense during the nine months ended September 30, 2015 is attributed to the higher borrowings outstanding from our revolving credit facility resulting from acquisitions of oil properties in November 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, oil and natural gas prices, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.
Crude oil prices have fallen to nine-year lows, impacting the way we conduct business. We have implemented a number of adjustments to strengthen our financial position. In addition to restructuring our commodity derivative contracts during the first quarter of 2015 to provide greater oil price protection over a longer period of time, we are aggressively pursuing costs reductions in order to improve profitability.
Our liquidity position at September 30, 2015, consisted of approximately $1.0 million of available cash, and $26.0 million of available borrowings under our revolving credit facility ($220.0 million borrowing base less $194.0 million of outstanding borrowings). Our borrowing base was revised downward from $240.0 million to $220.0 million upon the scheduled borrowing redetermination in April 2, 2015. Borrowings under the revolving credit facility may not exceed our current borrowing base of $220.0 million. We initiated our Fall 2015 borrowing base redetermination in October 2015 and expect to finalize this process in late November. We expect that our borrowing base will be reduced as a result of continued declines in oil and natural gas prices, however, the precise amount of the reduction is not known at this time.
Our primary use of capital has been for the acquisition and development of oil and natural gas properties. Our future success in growing reserves and production volumes will be highly dependent on the capital resources available and our success in drilling or acquiring additional reserves. As we pursue profitable reserves and production growth, we continually monitor our liquidity and the credit markets and based upon current expectations, we believe our liquidity and capital resources will be sufficient to conduct business and operations. Additionally, we continue to monitor events and circumstances surrounding each of the lenders in our revolving credit facility.

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

	Nine Months Ended September 30,	
	2015	2014
Operating activities	$31,334	$39,580
Investing activities	(11,251)	(62,913)
Financing activities	(22,354)	23,469

Operating Activities. Net cash provided by operating activities was approximately $31.3 million and approximately $39.6 million for the nine months ended September 30, 2015 and 2014, respectively. The $8.3 million decrease from 2014 to 2015 was primarily attributable to decreased oil sales revenues due to lower oil prices and a decrease in working capital, primarily related to lower accounts receivable as a result of lower oil and natural gas sales in 2015, offset by higher cash settlements on derivatives.
Investing Activities. Net cash used in investing activities was approximately $11.3 million and approximately $62.9 million for the nine months ended September 30, 2015 and 2014, respectively. Cash used in investing activities during the nine months ended September 30, 2015 included capital expenditures of approximately $11.3 million primarily for drilling and completion activities in our Northeastern Oklahoma and Permian properties. 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 related to acquisitions in 2014 included amounts paid for the properties acquired from our affiliate Mid-Con Energy III, LLC in February and August 2014, Liberty County waterflood unit acquired in August 2014, and the acquisition of working interest in our Southern Oklahoma core area in May 2014.
Financing Activities. Our cash flows from financing activities consisted primarily of proceeds from and payments on our revolving credit facility and distributions to unitholders. Cash used in financing activities during the nine months ended September 30, 2015 was approximately $22.4 million and included cash distributions to unitholders of approximately $11.3 million, net payments on our revolving credit facility of approximately $11.0 million, and

approximately $0.1 million of incremental offering costs from our November 2014 public offering. Cash provided by financing activities during the nine months ended September 30, 2014 was approximately $23.5 million and 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, cash distributions to our unitholders of approximately $32.4 million and $0.2 million of debt issuance costs related to the redeterminations of our borrowing capacity during 2014.

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. Given the current commodity pricing environment where oil prices are near a nine year low, we have limited capital spending to include only the most attractive development projects with a more conservative approach than in prior years. We actively review oil and natural gas acquisition opportunities on an ongoing basis and accordingly, expect to be well positioned to capitalize on attractive acquisitions in the current oil price environment. We have historically funded acquisitions through a combination of cash, available borrowing capacity under our current revolving credit facility and through the issuance of equity. We expect to finance any significant acquisition of oil and natural gas properties through the issuance of equity, debt financing or borrowings under our revolving credit facility.

We currently expect capital spending for the remainder of 2015 for the development, growth and maintenance of our oil and natural gas properties to be approximately $3.8 million. We will consider adjustments to this capital program based on our assessment of additional development opportunities that are identified during the year and the cash available to invest in our development projects.

Revolving Credit Facility

We have 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 $220.0 million as determined at April 2, 2015.

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. The remaining borrowing capacity under our revolving credit facility was approximately $26.0 million at September 30, 2015. 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, 2015.

With the April 2, 2015 redetermination, our borrowing base was reduced to $220.0 million from $240.0 million. As noted above, we initiated our Fall 2015 borrowing base redetermination in October 2015 and expect to finalize this process in late November. We do expect that our borrowing base will be reduced as a result of continued declines in oil and natural gas prices, however, the precise amount of the reduction is not known at this time.

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, 2015, our open commodity derivative contracts were in a net asset position with a fair value of approximately $28.7 million. All of our commodity derivative contracts are with major financial institutions who are also participant lenders in our revolving credit facility. 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, 2015, all of our counterparties had performed pursuant to their commodity derivative contracts.

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

Off–Balance Sheet Arrangements

As of September 30, 2015, 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, 2017 and is to be applied retrospectively. Early adoption is permitted. We are currently evaluating the impact the pronouncement will have on our consolidated financial statements and related disclosures.

In February 2015, the Financial Accounting Standards Board issued Accounting Standards Update No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which provides guidance on the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities such as limited partnerships, limited liability corporations, and securitization structures (collateralized debt obligations, collateralized loan obligations, and mortgage-backed security transactions). In addition to reducing the number of consolidation models from four to two, the guidance simplifies and improves current guidance by placing more emphasis on risk of loss when determining a controlling financial interest and reducing the frequency of the application of related-party guidance when determining a controlling financial interest in a VIE. The standard is effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period, with early adoption permitted. We are currently evaluating the effect, if any, that this new guidance will have on our consolidated financial statements and related disclosures.

In April 2015, the Financial Accounting Board issued Accounting Standards Update No. 2015-03, Interest: Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The update requires debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of being presented as an asset. Debt disclosures will include the face amount of the debt liability and the effective interest rate. The update requires retrospective application and represents a change in accounting principle. The update is effective for fiscal years beginning after December 15, 2015, with early adoption 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 a variety of market risks including commodity price risk, interest rate risk and credit risk. 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. The following should be read in conjunction with the financial statements and related notes included elsewhere in this Form10-Q and in our Annual Report.

Commodity Price Risk

Our primary market risk exposure is the pricing we receive for our oil and natural gas production. Historically, energy prices have exhibited, and are generally expected to continue to exhibit some of the highest volatility levels observed within the commodity and financial markets. The prices we receive for our oil and natural gas production depend on many factors outside of our control, such as the strength of the global economy and changes in supply and demand. The objective of our risk management program is to achieve more predictable cash flows by reducing our exposure to short-term fluctuations in the prices of oil and natural gas. We believe this strategy will serve to secure a baseline portion of our revenues and, by retaining some opportunity to participate in upward price movements, may also enable us to realize higher revenues during periods when prices rise. To this end, we utilize commodity derivatives-namely swaps, calls and puts-to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. We enter into commodity derivative contracts and/or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so.

Our commodity 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 commodity 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, 2015, was a net asset of approximately $28.7 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 $3.8 million. Please see "Item 1. Financial Statements" contained herein for additional information.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to debt obligations. At September 30, 2015, we had debt outstanding of $194.0 million, with an effective interest rate of approximately 2.9%. 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 $0.6 million for the nine months ended September 30, 2015. Our revolving credit facility allows borrowings up to $220.0 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 are subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current 2015 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, 2015. 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, 2015, 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, 2014.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

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

Exhibit No.	Exhibit Description
10.1	Amendment No.6 to Credit Agreement, dated as of February 12, 2015, 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 February 17, 2015).
10.2+	Form of Equity-Settled Phantom Unit Agreement (for employees of our Affiliate)
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 2, 2015	By:	/s/ Michael D. Peterson
		Michael D. Peterson
		Chief Financial Officer