Mid-Con Energy Partners, LP
Form 10-Q
November 14, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2017

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)

2431 East 61st Street, Suite 850

Tulsa, Oklahoma 74136

(Address of principal executive offices and zip code)

(918) 743-7575

(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company
Emerging Growth Company		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of November 14, 2017, the registrant had 30,091,463 common units.

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FORWARD-LOOKING STATEMENTS

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

- volatility or continued low or further declining commodity prices;
- revisions to oil and natural gas reserves estimates as a result of changes in commodity prices;
- effectiveness of risk management activities;
- business strategies;
- future financial and operating results;
- our ability to pay distributions;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- future capital requirements and availability of financing;
- technology;
- realized oil and natural gas prices;
- 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;
- 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," "
"forecast," "guidance," "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, 2016 ("Annual Report") and Part II - Item 1A. in this Form 10-Q. 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 Securities and Exchange Commission ("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 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, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$2,588	$ 2,359
Accounts receivable		
Oil and natural gas sales	4,605	5,302
Other	83	233
Derivative financial instruments	42	—
Prepaids and other	149	512
Total current assets	7,467	8,406
Property and equipment		
Proved oil and natural gas properties, successful efforts method	454,566	441,479
Other property and equipment	852	289
Accumulated depletion, depreciation, amortization and impairment	(212,922)	(176,551)
Total property and equipment, net	242,496	265,217
Derivative financial instruments	187	—
Other assets	1,640	2,663
Total assets	$251,790	$ 276,286
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$532	$ 256
Related parties	3,759	3,431
Derivative financial instruments	784	5,314
Accrued liabilities	897	146
Total current liabilities	5,972	9,147
Derivative financial instruments	—	2,495
Long-term debt	122,000	122,000
Other long term liabilities	75	93
Asset retirement obligations	12,384	11,331
Commitments and contingencies		
Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	20,253	19,570
Equity, per accompanying statements		
Partnership equity		

General partner interest	(470)	(248)
Limited partners - 30,091,463 and 29,912,230 units issued and outstanding, respectively	91,576	111,898
Total equity	91,106	111,650
Total liabilities, convertible preferred units and equity	$251,790	$ 276,286

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,	
	2017	2016	2017	2016
Revenues				
Oil sales	$13,731	$14,012	$42,343	$39,565
Natural gas sales	233	398	917	891
(Loss) gain on derivatives, net	(2,749)	(444)	2,916	(7,964)
Total revenues	11,215	13,966	46,176	32,492
Operating costs and expenses				
Lease operating expenses	6,122	5,709	16,695	17,551
Oil and natural gas production taxes	857	753	2,366	2,077
Impairment of proved oil and natural gas properties	4,850	—	22,522	895
Impairment of proved oil and natural gas properties sold	—	—	—	3,578
Depreciation, depletion and amortization	4,350	5,665	13,850	17,550
Accretion of discount on asset retirement obligations	142	127	386	443
General and administrative	1,188	1,715	4,485	5,281
Total operating costs and expenses	17,509	13,969	60,304	47,375
Loss on sales of oil and natural gas properties, net	—	(530)	—	(517)
Loss from operations	(6,294)	(533)	(14,128)	(15,400)
Other (expense) income				
Interest income	3	4	8	9
Interest expense	(1,626)	(1,728)	(4,615)	(5,981)
Other income (expense)	4	(164)	70	(131)
Loss on settlements of asset retirement obligations	(8)	—	(13)	—
Total other expense	(1,627)	(1,888)	(4,550)	(6,103)
Net loss	(7,921)	(2,421)	(18,678)	(21,503)
Less: Distributions to preferred unitholders	783	440	2,275	440
Less: General partner's interest in net loss	(94)	(29)	(222)	(256)
Limited partners' interest in net loss	$(8,610)	$(2,832)	$(20,731)	$(21,687)
Limited partners' interest in net loss per unit				
Basic and diluted	$(0.29)	$(0.09)	$(0.69)	$(0.73)
Weighted average limited partner units outstanding				
Limited partner units (basic and diluted)	30,042	29,868	29,972	29,807

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, 2017	2016
Cash Flows from Operating Activities		
Net loss	$(18,678)	$(21,503)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	13,850	17,550
Debt issuance costs amortization	1,023	1,019
Accretion of discount on asset retirement obligations	386	443
Impairment of proved oil and natural gas properties	22,522	895
Impairment of proved oil and natural gas properties sold	—	3,578
Loss on settlements of asset retirement obligations	13	—
Cash paid for settlements of asset retirement obligations	(30)	—
Mark to market on derivatives		
(Gain) loss on derivatives, net	(2,916)	7,964
Cash settlements received for matured derivatives	524	18,467
Cash settlements received from early termination of derivatives	147	5,820
Cash premiums paid for derivatives	(5,009)	(3,766)
Loss on sale of oil and natural gas properties	—	517
Non-cash equity-based compensation	409	961
Changes in operating assets and liabilities		
Accounts receivable	697	(160)
Other receivables	150	4,805
Prepaids and other	363	326
Accounts payable - trade and accrued liabilities	1,009	80
Accounts payable - related parties	(557)	(1,368)
Net cash provided by operating activities	13,903	35,628
Cash Flows from Investing Activities		
Acquisitions of oil and natural gas properties	(4,668)	(19,055)
Additions to oil and natural gas properties	(7,281)	(5,111)
Additions to other property and equipment	(133)	(124)
Proceeds from sale of oil and natural gas properties	—	17,312
Net cash used in investing activities	(12,082)	(6,978)
Cash Flows from Financing Activities		
Proceeds from line of credit	6,000	—
Payments on line of credit	(6,000)	(52,100)
Offering costs	(92)	(16)
Debt issuance costs	—	(9)
Proceeds from sale of convertible preferred units, net of offering costs	—	24,975
Distributions to Class A convertible preferred units	(1,500)	—
Net cash used in financing activities	(1,592)	(27,150)

Net increase in cash and cash equivalents	229	1,500
Beginning cash and cash equivalents	2,359	615
Ending cash and cash equivalents	$2,588	$2,115

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Changes in Equity

(in thousands)

(Unaudited)

	General Partner	Limited Partners Units	Limited Partners Amount	Total Equity
Balance, December 31, 2016	$ (248)	29,912	$111,898	$111,650
Equity-based compensation	—	179	409	409
Distributions to Class A convertible preferred units	—	—	(1,500)	(1,500)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(775)	(775)
Net loss	(222)	—	(18,456)	(18,678)
Balance, September 30, 2017	$ (470)	30,091	$91,576	$91,106

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

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,” or 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 common units representing limited partner interests in us (“common units”) are listed on the National Association of Securities Dealers Automated Quotation System Global Select Market (“NASDAQ”) under the symbol “MCEP.” Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.

Basis of Presentation

Our unaudited condensed consolidated financial statements are 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, 2016, 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 made are adequate to make the information not misleading.

The unaudited condensed consolidated financial statements include 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. All intercompany transactions and account balances have been eliminated.

Reclassifications

Certain amounts in the financial statements for the prior years have been reclassified to conform to the 2017 presentation. These reclassifications have no impact on previously reported total assets, total liabilities, net income (loss) or total operating cash flows.

Non-cash Investing, Financing and Supplemental Cash Flow Information

The following presents the non-cash investing, financing and supplemental cash flow information for the periods presented:

	Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Non-cash investing information		
Change in oil and natural gas properties - accrued	$885	$(513)

Change in oil and natural gas properties - accrued receivable, acquisition post-close	$—	$(419)
Change in oil and natural gas properties - accrued receivable, divestiture post-close	$—	$(354)
Change in other property and equipment - accrued	$—	$14
Change in other property and equipment - tenant improvement allowance	$—	$124
Non-cash financing information		
Change in Class A Preferred Units - accrued offering costs	$—	$(302)
Supplemental cash flow information		
Cash paid for interest	$3,566	$5,063

Note 2. Acquisitions and Divestitures

Acquisitions

Acquisitions are accounted for under the acquisition method of accounting. The assets acquired and liabilities assumed in acquisitions are recorded in our unaudited condensed consolidated balance sheets at their estimated fair values as of the acquisition date using assumptions that represent Level 3 fair value measurement inputs. See Note 5 in this section for additional discussion of our fair value measurements. Results of operations attributable to the acquisition subsequent to the closing are included in our unaudited condensed consolidated statements of operations.

Permian Bolt-On

In August 2016, we acquired multiple oil and natural gas properties located in Nolan County, Texas (the “Permian Bolt-On”) for cash consideration of approximately $18.7 million, after post-closing purchase price adjustments. The transaction was funded by a private offering of $25.0 million Class A Convertible Preferred Units (“Class A Preferred Units”). See Note 9 in this section for additional information regarding the issuance of the Class A Preferred Units. For the three months and nine months ended September 30, 2017, our unaudited condensed consolidated statements of operations included revenues of approximately $2.0 million and approximately $6.2 million, respectively, and expenses of approximately $1.4 million and approximately $4.3 million, respectively, related to the oil and natural gas properties acquired. For the three and nine months ended September 30, 2016, our unaudited condensed consolidated statements of operations included revenues of approximately $0.8 million and expenses of approximately $0.7 million related to the oil and natural gas properties acquired. The recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets acquired	
Oil and natural gas properties	$19,323
Total assets acquired	19,323
Fair value of net liabilities assumed	
Asset retirement obligation	622
Net assets acquired	$18,701

Wheatland

In June 2017, we acquired multiple oil and natural gas properties located in Oklahoma County and Cleveland County, Oklahoma (“Wheatland”) for cash consideration of approximately $4.2 million, prior to post-closing purchase price adjustments. For the three months ended September 30, 2017, our unaudited condensed consolidated statements of operations included revenues of approximately $0.6 million and expenses of approximately $0.4 million related to the oil and natural gas properties acquired. For the nine months ended September 30, 2017, our unaudited condensed consolidated statements of operations included revenues of approximately $0.7 million and expenses of approximately $0.5 million related to the oil and natural gas properties acquired. The recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

Fair value of net assets acquired	
Oil and natural gas properties	$4,465
Other property and equipment	127
Total assets acquired	4,592
Fair value of net liabilities assumed	
Asset retirement obligation	407

Net assets acquired	$4,185

Divestitures

Hugoton

In July 2016, we sold the properties located in our Hugoton core area for cash proceeds of approximately $17.6 million, including post-closing purchase price adjustments and recognized a loss of approximately $0.6 million. Additionally, we recorded impairment of proved oil and natural gas properties of approximately $3.6 million when these properties were originally reported as held for sale. For the three months ended September 30, 2016, our unaudited condensed consolidated statements of operations included revenues of approximately $0.6 million and expenses of approximately $0.6 million related to the oil and natural gas properties sold. For the nine months ended September 30, 2016, our unaudited condensed consolidated statements of operations included revenues of approximately $3.6 million and expenses of approximately $7.7

million related to the oil and natural gas properties sold. Effective at closing, the operations and cash flows of these properties were eliminated from the ongoing operations of the Partnership and the Partnership has no continuing involvement in these properties. This divestiture did not represent a strategic shift and did not have a major effect on the Partnership's operations or financial results.

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") and ME3 Oilfield Service, LLC ("ME3 Oilfield Service"), 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. The Long-Term Incentive Program is administered by Charles R. Olmstead, Executive Chairman of the Board, and Jeffrey R. Olmstead, President and Chief Executive Officer, and approved by the Board of Directors of our general partner (the "Board"). We account for unrestricted, restricted and equity-settled phantom unit awards as equity awards since they are settled by issuing common units. 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.

On January 1, 2017, we adopted ASU 2016-09 Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09") and elected to recognize forfeitures of equity awards as they occur. The cumulative effect of adopting ASU 2016-09 was determined to be immaterial and no adjustment to retained earnings was made.

The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at September 30, 2017:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,212,706)
Restricted units granted, net of forfeitures	(400,424)
Equity-settled phantom units granted, net of forfeitures	(483,000)
Awards available for future grant	1,417,870

We recognized approximately $0.1 million and $0.4 million of total equity-based compensation expense for the three and nine months ended September 30, 2017, respectively, and we recognized approximately $0.3 million and $1.0 million of total equity-based compensation expense for the three and nine months ended September 30, 2016, respectively. These costs are reported as a component of general and administrative expenses ("G&A") in our unaudited condensed consolidated statements of operations.

Unrestricted Unit Awards

During the nine months ended September 30, 2017, we granted 25,400 unrestricted units with an average grant date fair value of $2.65 per unit. During the nine months ended September 30, 2016, we granted 73,932 unrestricted units with an average grant date fair value of $1.20 per unit.

Restricted Unit Awards

Restricted units vest over a two- or three-year period. As of September 30, 2017, there were approximately $0.01 million of unrecognized compensation costs related to non-vested restricted units. These costs are expected to be recognized over a weighted average period of approximately four months.

A summary of our restricted unit awards for the nine months ended September 30, 2017, is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2016	76,922	$ 5.67
Units granted	—	—
Units vested	(69,560)	5.76
Units forfeited	—	—
Outstanding at September 30, 2017	7,362	$ 4.88

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a two- or three-year period and do not have any rights or privileges of a common unitholder, including right to distributions, until vesting and the resulting conversion into common units. During the nine months ended September 30, 2017, we granted 27,000 equity-settled phantom units with a two-year vesting period and 14,500 equity-settled phantom units with a three-year vesting period. During the nine months ended September 30, 2016, we granted 347,500 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years and 27,000 equity-settled phantom awards with a three-year vesting period. As of September 30, 2017, there were approximately $0.2 million of unrecognized compensation costs related to non-vested equity-settled phantom units. These costs are expected to be recognized over a weighted average period of approximately thirteen months.

A summary of our equity-settled phantom unit awards for the nine months ended September 30, 2017, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2016	287,659	$ 1.64
Units granted	41,500	1.60
Units vested	(153,833)	1.70
Units forfeited	(16,000)	2.83
Outstanding at September 30, 2017	159,326	$ 1.48

Note 4. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts 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, or as required by our lenders. These contracts are presented as derivative financial instruments on our unaudited condensed consolidated financial statements. We account for our commodity derivative contracts at fair value. See Note 5 in this section for a description of our fair value measurements.

We do not designate derivatives as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of our commodity 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. In addition to mark-to-market adjustments, gains or losses arise from net amounts paid or received on monthly settlements, proceeds from or payments for termination of contracts prior to their expiration and premiums paid or received for new contracts. Any deferred premiums are recorded as a liability and recognized in earnings as the related contracts mature. Gains and losses on derivatives are included in cash flows from operating activities. Pursuant to the accounting standard that permits netting of assets and liabilities where the right of offset exists, we present the fair value of commodity derivative contracts on a net basis.

At September 30, 2017, our commodity derivative contracts were in a net liability position with a fair value of approximately $0.6 million and at December 31, 2016, a net liability position with a fair value of approximately $7.8 million. All of our commodity derivative contracts are with major financial institutions that are also lenders under our revolving credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our commodity derivative contracts under lower commodity prices and we could incur a loss. As of September 30, 2017, all of our counterparties have performed pursuant to the terms of their commodity derivative contracts.

The following tables summarize the gross fair value by the appropriate balance sheet classification, even when the derivative financial instruments are subject to netting arrangements and qualify for net presentation, in our unaudited condensed consolidated balance sheets at September 30, 2017, and December 31, 2016:

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
	(in thousands)		
September 30, 2017			
Assets			
Derivative financial instruments - current asset	$266	$ (224)	$ 42
Derivative financial instruments - long-term asset	627	(440)	187
Total	893	(664)	229
Liabilities			
Derivative financial instruments - current liability	(769)	(15)	(784)
Derivative deferred premium - current liability	(239)	239	—
Derivative financial instruments - long-term liability	(239)	239	—
Derivative deferred premium - long-term liability	(201)	201	—
Total	(1,448)	664	(784)
Net Liability	$(555)	$ —	$ (555)

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets

	(in thousands)		
December 31, 2016			
Assets			
Derivative financial instruments - current asset	$1,570	$ (1,570)	$ —
Derivative financial instruments - long-term asset	406	(406)	—
Total	1,976	(1,976)	—
Liabilities			
Derivative financial instruments - current liability	(1,836)	(3,478)	(5,314)
Derivative deferred premium - current liability	(5,048)	5,048	—
Derivative financial instruments - long-term liability	(2,500)	5	(2,495)
Derivative deferred premium - long-term liability	(401)	401	—
Total	(9,785)	1,976	(7,809)
Net Liability	$(7,809)	$ —	$ (7,809)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Net settlements on matured derivatives[1]	$323	$1,182	$524	$18,467
Net settlements on early terminations of derivatives[1]	147	5,820	147	5,820
Net change in fair value of derivatives	(3,219)	(7,446)	2,245	(32,251)
Total (loss) gain on derivatives, net	$(2,749)	$(444)	$2,916	$(7,964)

[1] The settlement amount does not include premiums paid attributable to contracts that matured or early terminated during the respective period.

At September 30, 2017, and December 31, 2016, our commodity derivative contracts had maturities at various dates through December 2019 and were comprised of commodity price swap, put and collar contracts. At September 30, 2017, we had the following oil derivatives net positions:

Period Covered	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2017	$ 51.54	$ -	1,957	WTI
Collars - 2017	$ 45.00	$ 52.35	652	WTI
Swaps - 2018	$ 50.00	$ -	164	WTI
Collars - 2018	$ 44.38	$ 55.52	1,315	WTI
Puts - 2018	$ 45.00	$ -	164	WTI
Collars - 2019	$ 50.00	$ 60.52	427	WTI

At December 31, 2016, we had the following oil derivatives net positions:

Period Covered	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Collars - 2017	$ 43.75	$ 50.68	658	WTI
Puts - 2017	$ 50.00	$ —	1,932	WTI

Collars - 2018	$ 44.38	$ 55.52	1,315	WTI
Puts - 2018	$ 45.00	$ —	164	WTI
Collars - 2019	$ 50.00	$ 60.52	427	WTI

Note 5. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our unaudited condensed consolidated balance sheets for cash, accounts receivable and accounts payable approximate their fair values. The carrying amount of 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 commodity derivative contracts at fair value as discussed in “Assets and Liabilities Measured at Fair Value on a Recurring Basis” below.

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). 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. We consider active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an on-going basis.

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 2 instruments primarily include swap, call, put and collar contracts.

Level 3—Financial assets and liabilities for which values are based on prices or valuation approaches 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. We had no transfers in or out of Levels 1, 2 or 3 at September 30, 2017, and December 31, 2016.

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 material changes in valuation approach or related inputs for the nine months ended September 30, 2017, and for the year ended December 31, 2016.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We account for commodity derivative contracts and their corresponding deferred premiums at fair value on a recurring basis utilizing certain pricing models. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. The Partnership's deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as the Partnership utilizes a net present value calculation to determine the valuation. See Note 4 in this section for a summary of our derivative financial instruments.

The following sets forth, by level within the hierarchy, the value of our assets and liabilities measured at fair value on a recurring basis as of September 30, 2017, and December 31, 2016:

	Level 1	Level 2	Level 3	Fair Value
	(in thousands)			

September 30, 2017				
Derivative financial instruments - asset	$—	$893	$—	$893
Derivative financial instruments - liability	$—	$1,008	$—	$1,008
Derivative deferred premiums - liability	$—	$—	$440	$440
December 31, 2016				
Derivative financial instruments - asset	$—	$1,976	$—	$1,976
Derivative financial instruments - liability	$—	$4,336	$—	$4,336
Derivative deferred premiums - liability	$—	$—	$5,449	$5,449

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

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
	(in thousands)	
Balance of Level 3 at beginning of period	$ (5,449)	$ (9,973)
Derivative deferred premiums - purchases	—	(516)
Derivative deferred premiums - settlements	5,009	5,040
Balance of Level 3 at end of period	$ (440)	$ (5,449)

Assets and Liabilities Measured at Fair Value on a Non-recurring Basis

Asset Retirement Obligations

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

Acquisitions

The estimated fair values of proved oil and natural gas properties acquired in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. Based on the unobservable nature of certain of the inputs, the estimated fair value of the oil and natural gas properties acquired is deemed to use Level 3 inputs. See Note 2 in this section for further discussion of the Partnership's acquisitions.

Reserves

We calculate the estimated fair values of reserves and properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of reserves, future operating and developmental costs, future commodity prices, a market-based weighted average cost of capital rate and the rate at which future cash flows are discounted to estimate present value. We discount future values by a per annum rate of 10%. We believe this rate approximates our long-term cost of capital and accordingly, is well aligned with our internal business decisions. The underlying commodity prices embedded in our estimated cash flows begin with Level 1 NYMEX-WTI forward curve pricing, less Level 3 assumptions that include location, pricing adjustments and quality differentials.

Impairment

The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. For the three months ended September 30, 2017, we recorded non-cash impairment expense of approximately $4.9 million primarily on one of our Permian projects where late-stage waterflood efforts in select wells in the field have longer than anticipated response times to injection. The majority of the non-cash impairment expense of approximately $22.5 million for the nine months ended September 30, 2017, was due to margin compression over the reserve life caused by lower future oil pricing and a higher cost profile on one of our Northeastern Oklahoma projects. There were no impairment charges for the three months ended September 30, 2016. For the nine months ended September 30, 2016, we recorded non-cash impairment expense of approximately $0.9 million in our Permian core area due to a revision of reserve estimates at one property. These impairment expenses are included in “Impairment of proved oil and natural gas properties” in our unaudited condensed consolidated statements of operations.

There were no impairment charges related to assets held for sale for the three months ended September 30, 2016. For the nine months ended September 30, 2016, we recorded non-cash impairment expense of approximately $3.6 million related to the Hugoton divestiture to reduce the carrying amount of those assets to their fair value. These assets and liabilities were deemed to meet held for sale accounting criteria as of June 30, 2016, accordingly, the impairment is included in “Impairment of proved oil and natural gas properties sold” in our consolidated statements of operations.

Note 6. Asset Retirement Obligations

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas operations. These ARO are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or successfully drilling a well and determine our ARO by calculating the present value of estimated cash flow related to the estimated future liability. Determining the removal and future restoration obligation requires management to make estimates and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future ARO on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. The liability is accreted each period toward its future value and is recorded in our unaudited condensed consolidated statements 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. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability.

As of September 30, 2017, and December 31, 2016, our ARO were reported as “Asset retirement obligations” in our unaudited condensed consolidated balance sheets. Changes in our ARO for the periods indicated are presented in the following table:

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
	(in thousands)	
Asset retirement obligations - beginning of period	$11,331	$ 12,679
Liabilities incurred for new wells and interest	759	747
Liabilities settled upon plugging and abandoning wells	(17)	—
Liabilities removed upon sale of wells	—	(2,827)
Revision of estimates	(75)	155
Accretion expense	386	577
Asset retirement obligations - end of period	$12,384	$ 11,331

Note 7. Debt

We had outstanding borrowings under our revolving credit facility of $122.0 million at September 30, 2017, and December 31, 2016, respectively. Our current revolving credit facility matures in November 2018.

The borrowing base of our revolving credit facility is collectively determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other variables. The borrowing base is subject to scheduled redeterminations in the spring and fall of each year with an additional redetermination, either at our request or at the request of the lenders, during the period between each scheduled borrowing base redetermination. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election, the greater of the prime rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50% and the one month adjusted London Interbank Offered Rate (“LIBOR”) plus 1.0%, all of which are subject to a margin that varies from 1.00% to 2.75% 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 the applicable LIBOR plus a margin that varies from 2.00% to 3.75% per annum according to the borrowing base usage. For the three months ended September 30, 2017, the average effective rate was approximately 4.02%. Any unused portion of the borrowing base will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

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 revolving credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, leverage ratios and restrictions on certain transactions and payments, including distributions. 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.

At the quarter ended September 30, 2017, we were not in compliance with our leverage calculation ratio. On November 10, 2017, the Partnership received a waiver from the Administrative Agent and the Lenders of our revolving credit facility waiving the noncompliance through the earlier of (a) December 15, 2017, or (b) the termination, for any reason, of the Purchase and Sale Agreement (the “Sale Agreement”), dated November 8, 2017, governing the sale of certain oil and gas properties located in Carter and Love Counties, Oklahoma (the “Southern Oklahoma divestiture”). We believe it is probable that we will cure the violation of the leverage calculation ratio by the end of the wavier period. Additionally, in conjunction with its fall 2017 borrowing base redetermination, the Partnership is in advanced discussions with its lenders to extend the credit facility subject to the satisfaction of certain conditions including the Southern Oklahoma divestiture (the “Extension”).

If the transactions contemplated by the Sale Agreement and the Extension are not timely completed, and we are unable to negotiate an additional waiver of the leverage calculation ratio with the Administrative Agent and the Lenders of our revolving credit facility, we may be deemed in default of the revolving credit facility. In that case, unless we are able to secure another form of financing, our lenders would be entitled to accelerate the amounts owed under the revolving credit facility or foreclose on our oil and natural gas properties, either of which would have a material effect on our business and financial condition.

During the spring 2016 semi-annual redetermination and amendment to the credit agreement completed in May 2016, the effective borrowing base as of June 1, 2016, was reduced to $163.0 million and was comprised of a $110.0 million conforming tranche and a permitted overadvance of $53.0 million. The permitted overadvance was scheduled to mature on November 1, 2016.

During August 2016, we completed a non-scheduled redetermination and amendment to the credit agreement in conjunction with our Permian Bolt-On acquisition. Among other changes, this amendment to the credit agreement increased the conforming borrowing base of the Partnership’s revolving credit facility to $140.0 million as of August 11, 2016, modified the definition of “Indebtedness” to exclude the Class A Preferred Units and modified the limitations on restricted payments to specifically provide for the payment of cash distributions on the Class A Preferred Units. The amendment also required that by August 18, 2016, we enter into commodity derivative contracts of not less than 75% of our 2017 projected monthly production and not less than 50% of our 2018 projected monthly production, calculated based on proved developed producing reserves at the time of the agreement. These requirements were satisfied with the execution of additional commodity derivative contracts maturing in 2018. The amendment also required that within 30 days we extend our collateral coverage to include the reserves acquired in the Permian Bolt-On acquisition.

During the fall 2016 semi-annual borrowing base redetermination of our revolving credit facility completed in October 2016, the lender group reaffirmed the existing conforming borrowing base of $140.0 million effective October 28, 2016. There were no changes to the terms or conditions of the credit agreement.

During the spring 2017 semi-annual borrowing base redetermination of our revolving credit facility completed in May 2017, the lender group reaffirmed the Partnership’s $140.0 million conforming borrowing base effective May 24, 2017. There were no changes to the terms or conditions of the credit agreement.

Note 8. Commitments and Contingencies

Leases

We lease corporate office space in Tulsa, Oklahoma and Abilene, Texas. We were also allocated office rent from Mid-Con Energy Operating through August 2016 for office space in Dallas, Texas. Total lease expenses were approximately $0.1 million each for the three months ended September 30, 2017, and 2016, and approximately $0.2 million and $0.3 million each for the nine months ended September 30, 2017, and 2016, respectively. These expenses are included in G&A in our unaudited condensed consolidated statements of operations.

Future minimum lease payments under the non-cancellable operating leases are presented in the following table (in thousands):

Remaining 2017	$122
2018	490
2019	413
2020	418
2021	423
Total	$1,866

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. 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. See Note 10 in this section for additional information.

Employment Agreements

Our general partner has entered into employment agreements with Charles R. Olmstead, Executive Chairman of the Board and Jeffrey R. Olmstead, President and Chief Executive Officer. The employment agreements automatically renew for one-year terms on August 1st of each year unless either we or the employee gives written notice of termination by at least the preceding February. 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 may specify from time to time, in roles consistent with such positions that are assigned to them. 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 $0.3 million to $0.6 million, including the value of vesting of any outstanding units.

Legal

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.

Note 9. Equity

Common Units

At September 30, 2017, and December 31, 2016, the Partnership's equity consisted of 30,091,463 and 29,912,230 common units, respectively, representing approximately a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution 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. In connection with the Class A Preferred Units purchase agreement described below, the Partnership suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date of the issuance of the Class A Preferred Units until the fifth anniversary thereof, unless the Partnership obtains the consent of a majority of the holders of the outstanding Class A Preferred Units.

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.

As of September 30, 2017, cash distributions to our common units continued to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions and also prohibits us from making common unit cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit 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.

Class A Preferred Units

On August 11, 2016, we completed a private placement of 11,627,906 Class A Preferred Units for an aggregate offering price of $25.0 million. The Class A Preferred Units were issued at a price of $2.15 per Class A Preferred Unit (the “Class A Unit Purchase Price”). Proceeds from this issuance were used to fund the Permian Bolt-On acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of approximately $24.6 million (net of issuance costs of approximately $0.4 million) in connection with the issuance of these Class A Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class A Preferred Units (approximately $18.6 million) and the beneficial conversion feature (approximately $6.0 million). A beneficial conversion feature is defined as a non-detachable conversion feature that is in the money at the commitment date. Per accounting guidance, we are required to allocate a portion of the proceeds from the Class A Preferred Units to the beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per-share value of our common units at the issuance date) and the proceeds attributed to the Class A Preferred Units. We record the accretion attributed to the beneficial conversion feature as a deemed distribution using the effective interest method over the five year period prior to the effective date of the holders conversion right. Accretion of the beneficial conversion feature was approximately $0.3 million and approximately $0.8 million for the three and nine months ended September 30, 2017, respectively. Accretion of the beneficial conversion feature was approximately $0.2 million for the three and nine months ended September 30, 2016.

The holders of our Class A Preferred Units are entitled to certain rights that are senior to the rights of holders of common units, such as rights to distributions and rights upon liquidation of the Partnership. We pay holders of the Class A Preferred Units a cumulative, quarterly cash distribution on all Class A Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership’s existing secured indebtedness prevents the payment of a cash distribution to all holders of the Class A Preferred Units, in kind (additional Class A Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end, or as otherwise permitted to accumulate pursuant to the Partnership Agreement. As of September 30, 2017, all Class A Preferred Unit distributions have been paid in cash. No payment or distribution on common units for any quarter is permitted prior to the payment in full of the Class A Preferred Units distribution (including any outstanding arrearages). At September 30, 2017, the Partnership had accrued approximately $0.5 million for the third quarter 2017 distributions that will be paid in cash in December 2017, subsequent to the close of the Southern Oklahoma divestiture.

The following table summarizes cash distributions paid on our Class A Preferred Units during the nine months ended September 30, 2017:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2017	October 1, 2016 - December 31, 2016	$ 0.043	$ 500
May 15, 2017	January 1, 2017 - March 31, 2017	$ 0.043	$ 500
August 14, 2017	April 1, 2017 - June 30, 2017	$ 0.043	$ 500

Prior to the five year anniversary of the closing date, each holder of the Class A Preferred Units has the right, subject to certain conditions, to convert all or a portion of their Class A Preferred Units into common units representing limited partner interests in the Partnership on a one-for-one basis, subject to adjustment for splits, subdivisions, combinations and reclassifications of the common units. Upon conversion of the Class A Preferred Units, the Partnership will pay any distributions (to the extent accrued and unpaid as of the then most recent Class A Preferred Units distribution date) on the converted units in cash.

Under the registration rights agreements entered into in connection with the Class A Preferred Units issuance, we were required to use reasonable best efforts to file, within 90 days of the closing date, a registration statement registering resales of common units issued or to be issued upon conversion of the Class A Preferred Units and have the registration statement declared effective within 180 days after the closing date. On June 14, 2017, the previously filed shelf registration statement on Form S-3 was declared effective by the SEC.

Allocation of Net Income (Loss)

Net income (loss), net of distributions on the Class A Preferred Units and amortization of the Class A Preferred Unit's beneficial conversion feature (see Class A Preferred Units section), is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership (exclusive of the Class A Preferred Units limited partnership interest) during the period. The allocation of net income (loss) is presented in our unaudited condensed consolidated statements of operations. In the event of net income, diluted net income per partner unit reflects the potential dilution of non-vested restricted stock awards and the conversion of Class A Preferred Units.

Note 10. Related Party Transactions

Agreements with Affiliates

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 our affiliate, 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. These expenses are included in G&A in our unaudited condensed consolidated statements of operations.

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are parties to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead associated with operating our properties. We and those third parties also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. The majority of these expenses are included in lease operating expenses ("LOE") in our unaudited condensed consolidated statements of operations.

Oilfield Services

We are party to operating agreements, pursuant to which our affiliate, Mid-Con Energy Operating, bills us for oilfield services performed by our affiliates, ME3 Oilfield Service and ME2 Well Services, LLC. These amounts are either included in LOE in our unaudited condensed consolidated statements of operations or are capitalized as part of oil and natural gas properties in our unaudited condensed consolidated balance sheets.

The following table summarizes the affiliates' transactions for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Amounts paid for				
Services agreement	$610	$914	$1,903	$2,440
Operating agreements	1,678	1,509	4,694	4,790
Oilfield services	809	778	2,476	2,274
	$3,097	$3,201	$9,073	$9,504

At September 30, 2017, we had a payable to our affiliate, Mid-Con Energy Operating, of approximately $3.8 million, comprised of a joint interest billing payable of approximately $3.6 million and a payable for operating services of approximately $0.2 million. At December 31, 2016, we had a payable to our affiliate, Mid-Con Energy Operating, of approximately $3.4 million, comprised of a joint interest billing payable of approximately $2.8 million and a payable for operating services of approximately $0.6 million. These amounts were included in accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued a comprehensive new revenue recognition standard that supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring those goods or services. The new standard also requires significantly expanded disclosure regarding the qualitative and quantitative information of an entity's nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The standard creates a five-step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's application impact to individual financial statement line items. In March, April, May and December 2016, the FASB issued new guidance in Topic 606, Revenue from Contracts with Customers, to address the following potential implementation issues of the new revenue standard: (a) to clarify the implementation guidance on principal versus agent considerations, (b) to clarify the identification of performance obligations and the licensing implementation guidance and (c) to address certain issues in the guidance on assessing collectability, presentation of sales taxes, non-cash consideration and completed contract modifications at transition. This standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. We plan to adopt this standard effective January 1, 2018, using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018, as an adjustment to opening retained earnings. We have completed our initial assessment and concluded that our revenue recognition under the new guidance will not materially differ from our current revenue recognition practice. Therefore, we do not expect a cumulative effect adjustment to opening retained earnings. We are still evaluating the impact this guidance will have on our processes and internal controls.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. We plan to adopt this standard on January 1, 2019 and believe the primary impact of adoption will be the recognition of assets and liabilities on our balance sheet for current operating leases. We are still evaluating the impact of this standard.

In August, 2016, the FASB issued ASU No. 2016-15, Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). The amendments in ASU 2016-15 address eight specific cash flow issues and apply to all entities that are required to present a statement of cash flows under FASB Accounting Standards Codification (FASB ASC) 230, Statement of Cash Flows. The amendments in ASU 2016-15 are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted, including adoption during an interim period. We plan to adopt this standard on January 1, 2018. Based on our initial evaluation, we do not anticipate a material impact to our consolidated financial statements upon adoption of this standard.

In January 2017, the FASB issued ASU No. 2017-01, "Business Combinations (Topic 805)," with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The amendments in this update provide a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output and remove the evaluation of whether a market participant could replace missing elements. This new guidance is effective for annual periods beginning after December 15, 2017, and early adoption is allowed. We are evaluating the impact it will have on our consolidated financial statements.

Note 12. Subsequent Events

Distributions

The Board declared a Class A Preferred Unit distribution for the third quarter of 2017, according to terms outlined in the Partnership Agreement. A cash distribution of $0.043 per Class A Preferred Unit, or approximately $0.5 million in aggregate, will be paid in December 2017 to holders of record subsequent to the close of the Southern Oklahoma divestiture.

Departure of Officer

On November 6, 2017, Mr. Matthew R. Lewis informed the Board of his resignation as Vice President and Chief Financial Officer of the General Partner to pursue other opportunities. Subsequent to Mr. Lewis' departure, his duties and responsibilities will be assumed by other members of the management team. Mr. Lewis did not resign due to any disagreement with the Partnership or any matter relating to the Company's operations, policies or practices. The Partnership did not enter into any agreement with Mr. Lewis as a result of his resignation. Mr. Lewis' resignation was effective immediately but he will continue to serve in an advisory role until November 30, 2017.

Southern Oklahoma Divestiture

On November 8, 2017, we entered into a definitive purchase and sale agreement to sell oil and natural gas assets within our Southern Oklahoma core area for an aggregate sale price of approximately $25.0 million, subject to customary post-closing sale price adjustments. Per the agreement, the effective date of the sale is October 1, 2017, and the closing date of the divestiture is November 30, 2017. Proceeds from the divestiture will be used to reduce borrowings outstanding under the Partnership's revolving credit facility.

Class B Convertible Preferred Units

On November 14, 2017, we entered into a definitive agreement to offer up to $15.0 million of Class B Convertible Preferred Units ("Class B Preferred Units") in a private offering subject to customary closing conditions. The Partnership will use the net proceeds from the offering for general partnership purposes, including but not limited to, future acquisitions and reduction of borrowings outstanding under the Partnership's revolving credit facility. The Class B Preferred Units will be issued at a price of $1.36 per preferred unit (the "Class B Unit Purchase Price"). The Partnership will pay holders of the Class B Preferred Units a cumulative, quarterly distribution in cash at an annual rate of 8.0%, or under certain circumstances, in additional preferred units, at an annual rate of 10.0%. At any time after the six month anniversary and prior to August 11, 2021, each holder of the preferred units may elect to convert all or any portion of their Class B Preferred Units into common units representing limited partner interests in the Partnership on a one-for-one basis. On August 11, 2021, each holder may elect to cause the Partnership to redeem all or any portion of their Class B Preferred Units for cash at the Class B Unit Purchase Price, and any remaining Class B Preferred Units will thereafter be converted to common units on a one-for-one basis.

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 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 EOR. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our 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 three core areas: Southern Oklahoma, Northeastern Oklahoma and Texas within the Eastern Shelf of the Permian Basin ("Permian"). Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Executive Summary - Third Quarter 2017

Operating Performance

- In the third quarter, the Partnership drilled nine producing wells, drilled two injection wells, returned eight wells to production, performed five recompletions and two capital workovers, converted six producing wells to injection and returned two wells to injection.
- In the Wheatland properties acquired in Cleveland and Oklahoma counties during the second quarter of 2017, the Partnership returned wells to production and injection, resulting in increased production in the third quarter.
- Positive initial waterflood response was observed in the second quarter of 2017 at two Permian properties as a result of new injection. The waterflood developments were expanded in the third quarter of 2017.

Distributions

- On August 14, 2017, we paid a cash distribution on the Class A Preferred Units of approximately $0.5 million, for the second quarter of 2017.

Business Environment

The markets for oil, natural gas and natural gas liquids have been volatile and may continue to be volatile in the future, which means that the price of oil and natural gas may fluctuate widely. Sustained periods of low prices for oil and natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. In general, the average oil and natural gas prices were higher during the comparable periods of 2017 measured against 2016. Our average sales price per barrel of oil ("Bbl"), excluding commodity derivative contracts, was $46.28 per Bbl and $37.43 per Bbl for the nine months ended September 30, 2017, and 2016, respectively. The volatility in commodity prices has impacted our unit price. During the nine months ended September 30, 2017, our common unit price fluctuated between a closing low of $0.94 per unit to a closing high of $3.22 per unit.

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts 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, or as required by our lenders. 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, 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 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 distributions to our unitholders. The amount of cash that we may distribute to our unitholders in the future 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.

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas properties, including:

- oil and natural gas production volumes;
- realized prices on the sale of oil and natural gas, including the effect of our commodity derivative contracts;
- LOE; and
- Adjusted EBITDA.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess the cash flow generated by our assets, without regard to financing methods, capital structure or historical cost basis and our ability to incur and service debt and fund capital expenditures.

In addition, management uses Adjusted EBITDA to evaluate actual potential cash flow available to reduce debt, develop existing reserves or acquire additional properties and pay distributions to our unitholders. Adjusted EBITDA is a non-U.S. GAAP measure and should not be considered an alternative to net income (loss), net cash provided by operating activities or any other performance or liquidity measure determined in accordance with U.S. GAAP. Our calculations of Adjusted EBITDA are not necessarily comparable to EBITDA or Adjusted EBITDA as calculated by other companies.

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues				
Oil sales	$13,731	$14,012	$42,343	$39,565
Natural gas sales	$233	$398	$917	$891
(Loss) gain on derivatives, net	$(2,749)	$(444)	$2,916	$(7,964)
Operating costs and expenses				
Lease operating expenses	$6,122	$5,709	$16,695	$17,551
Oil and natural gas production taxes	$857	$753	$2,366	$2,077
Impairment of oil and natural gas properties	$4,850	$—	$22,522	$895
Impairment of oil and natural gas properties sold	$—	$—	$—	$3,578
Depreciation, depletion and amortization	$4,350	$5,665	$13,850	$17,550
General and administrative [(1)]	$1,188	$1,715	$4,485	$5,281
Interest expense	$1,626	$1,728	$4,615	$5,981
Production				
Oil (MBbls)	304	339	915	1,057
Natural gas (MMcf)	105	149	339	409
Total (MBoe)	322	364	972	1,125
Average net production (Boe/d)	3,500	3,957	3,560	4,106
Average sales price				
Oil (per Bbl)				
Sales price	$45.17	$41.33	$46.28	$37.43
Effect of net settlements on matured derivative instruments	$(3.33)	$3.49	$(3.74)	$10.29
Realized oil price after derivatives	$41.84	$44.82	$42.54	$47.72
Natural gas (per Mcf)				
Sales price	$2.22	$2.67	$2.71	$2.18
Average unit costs per Boe				
Lease operating expenses	$19.01	$15.68	$17.18	$15.60
Oil and natural gas production taxes	$2.66	$2.07	$2.43	$1.85
Depreciation, depletion and amortization	$13.51	$15.56	$14.25	$15.60
General and administrative expenses	$3.69	$4.71	$4.61	$4.69

(1) G&A included non-cash equity-based compensation of approximately $0.1 million and approximately $0.4 million for the three and nine months ended September 30, 2017, and $0.3 million and $1.0 million for the three and nine months ended September 30, 2016.

Three Months Ended September 30, 2017 Compared with the Three Months Ended September 30, 2016

We reported net loss of approximately $7.9 million for the three months ended September 30, 2017, compared to a net loss of approximately $2.4 million for the three months ended September 30, 2016. Lower oil and natural gas production, the unfavorable net impact of derivatives, higher LOE and impairment expense, partially offset by lower depreciation, depletion and amortization (“DD&A”) and G&A expense were the primary factors attributable to the $5.5 million change.

Sales Revenues. Revenues from oil and natural gas sales for the three months ended September 30, 2017, were approximately $14.0 million compared to approximately $14.4 million for the three months ended September 30, 2016. The decrease in revenues was primarily due to lower production volumes, partially offset by higher oil prices. Our average sales price per Bbl, excluding commodity derivative contracts, for the three months ended September 30, 2017, was approximately $45.17 per Bbl compared to approximately $41.33 per Bbl for the three months ended September 30, 2016.

On average, production volumes for the three months ended September 30, 2017, were approximately 322 MBoe, or approximately 3,500 Boe per day. In comparison, total production volumes for the three months ended September 30, 2016, were approximately 364 MBoe, or approximately 3,957 Boe per day. The decrease in production volumes was due to the sale of our Hugoton properties, primary production declines at select properties in the Permian core area and increasing water cuts at select maturing waterflood properties in our Southern Oklahoma core area. Lower production volumes were partially offset by production from the Permian Bolt-On and Wheatland acquisition properties, successful new drill results at a Permian Bolt-On property and positive waterflood responses at key properties in our Permian and Northeastern Oklahoma core areas.

Effects of Commodity Derivative Contracts. For the three months ended September 30, 2017, we recorded a net loss on derivatives of approximately $2.8 million which was comprised of approximately $3.2 million of non-cash loss on changes in fair value of our commodity derivative contracts, approximately $0.3 million of gain on net cash settlements of our commodity derivative contracts and approximately $0.1 million of gain on net cash settlements for the early termination of commodity derivative contracts in September 2017. For the three months ended September 30, 2016, we recorded a net loss on derivatives of approximately $0.4 million which was comprised of approximately $7.4 million of non-cash loss on changes in fair value of commodity derivative contracts, approximately $1.2 million of gain on net cash settlements of derivative contracts and approximately $5.8 million of gain on net cash settlements for the early termination of commodity derivative contracts in July 2016.

Lease Operating Expenses. For the three months ended September 30, 2017, LOE was approximately $6.1 million, or approximately $19.01 per Boe, compared to approximately $5.7 million, or approximately $15.68 per Boe, for the three months ended September 30, 2016. The increase in total and per BOE LOE was due to increased ad valorem expense in the Permian core area and incremental costs from properties acquired, partially offset by the Hugoton divestiture. Additionally, the increase in per Boe LOE was due to lower production volumes.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues and exclude the effects of our commodity derivative contracts. Production taxes for the three months ended September 30, 2017, were approximately $0.9 million, or approximately $2.66 per Boe (effective tax rate of approximately 6.1%), compared to approximately $0.8 million, or approximately $2.07 per Boe (effective tax rate of approximately 5.2%) for the three months ended September 30, 2016. The increase in both production taxes, as a percentage of total sales and per Boe, was due to legislation that discontinued the EOR tax credit at one of our Northeastern Oklahoma units effective July 1, 2017.

Impairment Expense. For the three months ended September 30, 2017, we recorded approximately $4.9 million of non-cash impairment expense primarily on one of our Permian projects where late-stage waterflood efforts in select wells in the field have longer than anticipated response times to injection. For the three months ended September 30, 2016, we recorded no impairment charges.

Depreciation, Depletion and Amortization Expenses. DD&A for the three months ended September 30, 2017, was approximately $4.4 million, or approximately $13.51 per Boe, compared to approximately $5.7 million, or approximately $15.56 per Boe, for the three months ended September 30, 2016. The decrease in total and per Boe DD&A was due to decreases in depletion rates and production volumes. Depletion rate decreases were due to increased reserves and asset impairment recorded in the second quarter of 2017 which reduced the carrying value of our oil and natural gas properties.

General and Administrative Expenses. G&A was approximately $1.2 million, or approximately $3.69 per Boe, for the three months ended September 30, 2017, compared to approximately $1.7 million, or approximately $4.71 per Boe, for three months ended September 30, 2016. The decrease in G&A was partly due to lower compensation expense. G&A expenses included non-cash equity-based compensation of approximately $0.1 million and approximately $0.3 million for the three months ended September 30, 2017, and 2016, respectively. Additionally, there was a reduction in salaries and rent expense as the result of the relocation of our Dallas, Texas, headquarters to Tulsa, Oklahoma, in an effort to consolidate office space.

Interest Expense. Interest expense for the three months ended September 30, 2017, was approximately $1.6 million compared to approximately $1.7 million for the three months ended September 30, 2016. The decrease in interest expense was due to lower outstanding borrowings, partially offset by a higher effective interest rate based on an increase in the underlying market rate.

Nine Months Ended September 30, 2017 Compared with the Nine Months Ended September 30, 2016

We reported a net loss of approximately $18.7 million for the nine months ended September 30, 2017, compared to a net loss of approximately $21.5 million for the nine months ended September 30, 2016. A favorable net impact of derivatives, lower expenses (DD&A, interest, LOE and G&A) and higher oil and natural gas prices, partially offset by higher impairment expense and lower oil and natural gas production, were the primary factors attributable to the $2.8 million change.

Sales Revenues. Revenues from oil and natural gas sales for the nine months ended September 30, 2017, were approximately $43.3 million compared to approximately $40.5 million for the nine months ended September 30, 2016. The increase in revenues were primarily due to higher oil and natural gas prices. Our average sales price per Bbl, excluding commodity derivative contracts, for the nine months ended September 30, 2017, was $46.28 per Bbl, compared to approximately $37.43 per Bbl for the nine months ended September 30, 2016. The price increase was partially offset by lower production volumes.

On average, production volumes for the nine months ended September 30, 2017, were approximately 972 MBoe, or approximately 3,560 Boe per day. In comparison, production volumes for the nine months ended September 30, 2016, were approximately 1,125 MBoe, or approximately 4,106 Boe per day. The decrease in production volumes was primarily due to the sale of our Hugoton properties, primary production declines at select properties in our Permian core area and increasing water cuts at select maturing waterflood properties in our Southern Oklahoma core area. Lower production volumes were partially offset by production from the Permian Bolt-On and Wheatland acquisition properties, successful new drill results at a Permian Bolt-On property and positive waterflood responses at key properties in our Permian and Northeastern Oklahoma core areas.

Effects of Commodity Derivative Contracts. For the nine months ended September 30, 2017, we recorded a net gain on derivatives of approximately $2.9 million which was composed of approximately $2.3 million of non-cash gain on changes in fair value of our commodity derivative contracts, approximately $0.5 million of gain on net cash settlements of our commodity derivative contracts and approximately $0.1 million of gain on net cash settlements for the early termination of commodity derivative contracts in September 2017. For the nine months ended September 30, 2016, we recorded a net loss on derivatives of approximately $8.0 million which was comprised of approximately $32.3 million of non-cash loss on changes in fair value of our commodity derivative contracts, approximately $18.5 million of gain on net cash settlements of our commodity derivative contracts and approximately $5.8 million of gain on net cash settlements for the early termination of commodity derivative contracts in July 2016.

Lease Operating Expenses. For the nine months ended September 30, 2017, LOE was approximately $16.7 million, or approximately $17.18 per Boe, compared to approximately $17.6 million, or approximately $15.60 per Boe, for the nine months ended September 30, 2016. The decrease in total LOE was due to the divestiture of Hugoton properties and reduced spending in our Texas Gulf Coast area, partially offset by incremental costs associated with properties acquired in the Permian Bolt-On and Wheatland acquisitions, increased non-routine costs in Northeastern Oklahoma related to storm damage and increased ad valorem taxes in the Permian core area. The increase in average costs per Boe was due to lower production.

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. Production taxes for the nine months ended September 30, 2017, were approximately $2.4 million, or approximately $2.43 per Boe (effective tax rate of approximately 5.5%), compared to approximately $2.1 million, or approximately $1.85 per Boe (effective tax rate of approximately 5.1%), for the nine months ended September 30, 2016. The increase in both production taxes, as a percentage of total sales and per Boe, was primarily attributable to tax rebates received during 2016 comparable periods and legislation that discontinued the EOR tax credit at one of our Northeastern Oklahoma units effective July 1, 2017.

Impairment Expense. For the nine months ended September 30, 2017, we recorded approximately $22.5 million of non-cash impairment expense primarily on one of our Northeastern Oklahoma projects due to margin compression over the reserve life caused by lower future oil pricing and a higher cost profile at quarter end and on one of our Permian projects where late-stage waterflood efforts in select wells in the field have longer than anticipated response times to injection. For the nine months ended September 30, 2016, we recorded approximately $0.9 million of non-cash impairment expense due to revisions in reserve estimates on one of our Permian properties.

Depreciation, Depletion and Amortization Expenses. DD&A for the nine months ended September 30, 2017, was approximately $13.9 million, or approximately $14.25 per Boe, compared to approximately $17.6 million, or approximately $15.60 per Boe, for the nine months ended September 30, 2016. The decrease in total and per Boe DD&A was primarily due to decreases in depletion rates and production volumes, offset by the net impact of the Hugoton divestiture and the Permian Bolt-

On and Wheatland acquisitions. Depletion rate decreases were due to increased reserves and asset impairment recorded in the second quarter of 2017 which reduced the carrying value of our oil and natural gas properties.

General and Administrative Expenses. G&A was approximately $4.5 million, or approximately $4.61 per Boe, for the for the nine months ended September 30, 2017, compared to approximately $5.3 million, or approximately $4.69 per Boe, for the for the nine months ended September 30, 2016. The decrease in G&A was primarily due to lower equity-based compensation resulting from the lower price of our common units and fewer units issued. G&A included non-cash equity-based compensation of approximately $0.4 million and approximately $1.0 million for the nine months ended September 30, 2017, and 2016, respectively. Additionally, there was a reduction in salaries and rent expense as the result of the relocation of our Dallas, Texas, headquarters to Tulsa, Oklahoma, in an effort to consolidate office space. These reductions in G&A were partially offset by sales taxes related to the Wheatland acquisition and increased professional fees.

Interest Expense. Interest expense for the nine months ended September 30, 2017, was approximately $4.6 million, compared to approximately $6.0 million for the nine months ended September 30, 2016. The decrease in interest expense was due to lower borrowings outstanding and a lower effective interest rate.

Liquidity and Capital Resources

Our ability to finance our operations, fund our capital expenditures and acquisitions, meet or refinance our debt obligations and meet our collateral requirements will depend on our future cash flows. 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, operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. Historically, our primary use of cash has been for debt reduction, capital spending, including acquisitions and distributions.

Since November 2014, oil prices have been extremely volatile, impacting the way we conduct business. In response, we have implemented a number of adjustments to strengthen our financial position. We have continued to hedge a portion of our production to limit downside and volatility in the prevailing commodity price environment. We have aggressively pursued cost reductions to improve profitability and maximize cash flows. We further reduced the Partnership’s weighted average cash operating break-even costs per Boe with the July 2016 divestiture of our higher cost Hugoton core area and the properties acquired through the August 2016 Permian Bolt-On acquisition, which carry a lower cost profile on a relative basis. Additionally, in the third quarter 2015, we indefinitely suspended our quarterly cash distributions on common units.

Our liquidity position at September 30, 2017, consisted of approximately $2.6 million of available cash. Our borrowing base is redetermined in the spring and fall of each year. Depending on a number of financial and operating factors that can materially influence the cash flow generation of our business, including but not limited to, future oil and natural gas prices, sales from produced oil and natural gas volumes, and cash operating expenses, we could breach certain financial covenants under the revolving credit facility, which would constitute a default under the revolving credit facility. Such default, if not cured, would require a waiver from our lenders to avoid an event of default and, subject to certain limitations, subsequent acceleration of all amounts outstanding under the revolving credit facility and potential foreclosure on our oil and natural gas properties.

At the quarter ended September 30, 2017, we were not in compliance with our leverage calculation ratio. On November 10, 2017, the Partnership received a waiver from the Administrative Agent and the Lenders of our revolving credit facility waiving the noncompliance through the earlier of (a) December 15, 2017, or (b) the termination of the Sale Agreement, dated November 8, 2017, governing the Southern Oklahoma divestiture. We believe it is probable that we will cure the violation of the leverage calculation ratio by the end of the wavier period as a result of the Southern Oklahoma divestiture. Additionally, in conjunction with its fall 2017 borrowing base redetermination, the Partnership is in advanced discussions with its lenders for the Extension of the credit facility subject to the satisfaction of certain conditions including the Southern Oklahoma divestiture.

If the transactions contemplated by the Sale Agreement and the Extension are not timely completed, and we are unable to negotiate an additional waiver of the leverage calculation ratio with the Administrative Agent and the Lenders of our revolving credit facility, we may be deemed in default of the revolving credit facility. In that case, unless we are able to secure another form of financing, our lenders would be entitled to accelerate the amounts owed under the revolving credit facility or foreclose on our oil and natural gas properties, either of which would have a material effect on our business and financial condition.

Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures budget, meet our debt service requirements and fund our other commitments and obligations. Although we currently expect our sources of cash to be sufficient to meet our near-term liquidity needs, there can be no assurance that our liquidity requirements will continue to be satisfied due to the discretion of our lenders to potentially decrease our borrowing base. Due to the volatility of commodity prices, we may not be able to obtain funding in the equity or debt capital markets on terms we find acceptable. The cost of obtaining debt capital from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, and reduced and, in some cases, ceased to provide any new funding.

Cash Flows

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

	Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Operating activities	$13,903	$35,628
Investing activities	$(12,082)	$(6,978)
Financing activities	$(1,592)	$(27,150)

Operating Activities. Net cash provided by operating activities was approximately $13.9 million and approximately $35.6 million for the nine months ended September 30, 2017, and 2016, respectively. The $21.7 million change from 2016 to 2017 was primarily attributable to lower cash settlements received from matured derivatives.

Investing Activities. Net cash used in investing activities was approximately $12.1 million and approximately $7.0 million for the nine months ended September 30, 2017, and 2016, respectively. Cash used in investing activities during the nine months ended September 30, 2017, included approximately $7.3 million of capital expenditures for drilling and completion activities primarily in our Permian and Northeastern Oklahoma core areas and approximately $4.7 million for the acquisition of oil and natural gas properties in Central Oklahoma. Cash used in investing activities during the nine months ended September 30, 2016, included approximately $19.1 million for acquisitions of oil and natural gas properties in the Permian area and approximately $5.1 million of capital expenditures for drilling and completion activities primarily in our Permian and Northeastern Oklahoma core areas, partially offset by proceeds from the sale of our Hugoton oil and gas properties of approximately $17.3 million.

Financing Activities. Net cash used in financing activities was approximately $1.6 million and approximately $27.2 million for the nine months ended September 30, 2017, and 2016, respectively. Net cash used in financing activities during the nine months ended September 30, 2017, included distributions to preferred unitholders of approximately $1.5 million. Net cash used in financing activities during the nine months ended September 30, 2016, included payments on our revolving credit facility of approximately $52.1 million, partially offset by proceeds of approximately $25.0 million from the sale of Class A Preferred Units.

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 and develop producing assets that allow us to increase our production and asset base. To date, we have funded acquisition transactions through a combination of cash, available borrowing capacity under our revolving credit facility and through the issuance of equity, including convertible preferred units.

We currently expect capital spending for the remainder of 2017 for the development, growth and maintenance of our oil and natural gas properties to be approximately $1.7 million. We will consider adjustments to this capital program as business conditions and operating results warrant, in addition to our ongoing evaluation of additional development opportunities that are identified during the year.

Revolving Credit Facility

At September 30, 2017, our borrowing base was $140.0 million and outstanding borrowings under our revolving credit facility were $122.0 million. Our borrowing base is redetermined in the spring and fall of each year. As of November 14, 2017, in conjunction with our fall 2017 borrowing base redetermination, the Partnership is in advanced discussions with its lenders to extend the credit facility subject to the satisfaction of certain conditions included in the Southern Oklahoma divestiture. See

Note 7 to the unaudited condensed consolidated financial statements for additional information regarding our revolving credit facility.

Commodity Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) 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 or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts 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, or as required by our lenders. At September 30, 2017, we had commodity derivative contracts covering approximately 78%, 49% and 13%, respectively, of our estimated 2017, 2018 and 2019 average daily production (estimate calculated based on the mid-point of our full year 2017 Boe production guidance as released on November 14, 2017, and multiplied by a 94% oil weighting based on third quarter 2017 reported production volumes). See Note 4 to the unaudited condensed consolidated financial statements for additional information regarding our commodity derivative contracts.

Preferred Units

As of September 30, 2017, we have issued $25.0 million of Class A Preferred Units, which were issued during August 2016. Class A preferred unitholders receive a cumulative, quarterly cash distribution on all Class A Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership's existing secured indebtedness prevents the payment of a cash distribution to all holders of the Class A Preferred Units, in kind (additional Class A Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end, or as otherwise permitted to accumulate pursuant to the Partnership Agreement. See Note 9 to the unaudited condensed consolidated financial statements for additional information regarding Class A Preferred Units.

Off–Balance Sheet Arrangements

As of September 30, 2017, we had no off-balance sheet arrangements.

Recently Issued Accounting Pronouncements

See Note 11 to the unaudited condensed consolidated financial statements for additional information regarding recently issued accounting pronouncements.

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 disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

Our primary market risk exposure is the pricing we receive for our oil and natural gas sales. 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 sales depend on many factors outside of our control, such as the strength of the global economy and changes in supply and demand.

Our risk management program is intended to reduce exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivatives contracts (swaps, calls, puts and costless collars), 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 production over a fixed period of time. We enter into commodity derivative contracts 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, or as required by our lenders.

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require the counterparties to our commodity derivative contracts to post collateral, it is our policy to enter into commodity 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 commodity 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 are recorded at fair value and changes to the future commodity prices could have the effect of reducing net income and the value of our securities. The fair value of our oil commodity derivative contracts at September 30, 2017, was a net liability of approximately $0.6 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 derivative contracts of approximately $3.7 million. See Note 4 to the unaudited condensed consolidated financial statements for additional information regarding our commodity derivative contracts.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to debt obligations. At September 30, 2017, we had debt outstanding of $122.0 million, with an effective interest rate of 3.80%. 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 $0.5 million on an annual basis. See Note 7 to the unaudited condensed consolidated financial statements for additional information regarding our revolving credit facility.

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 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. We monitor our exposure to these counterparties primarily by reviewing credit ratings and payment history. As of September 30, 2017, our current purchasers had 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 accounting 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, 2017. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal 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 principal executive officer and principal 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, 2017, 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

Except for the risk factor discussed below, there have been no material changes with respect to the risk factors disclosed in our Annual Report for the year ended December 31, 2016.

If we do not maintain certain financial covenants under our revolving credit facility we may be deemed in breach, entitling our lenders to accelerate the amounts due under the facility or foreclose on our properties.

We are dependent on our revolving credit facility, and a change in a number of financial and operating factors that can materially influence the cash flow generation of our business, including but not limited to, future oil and natural gas prices, sales from produced oil and natural gas volumes, and cash operating expenses, could result in our breaching certain financial covenants under the revolving credit facility, which would constitute a default under the revolving credit facility. Such default, if not cured, would require a waiver from our lenders to avoid an event of default and, subject to certain limitations, subsequent acceleration of all amounts outstanding under the revolving credit facility and potential foreclosure on our oil and natural gas properties.

At the quarter ended September 30, 2017, we were not in compliance with our leverage calculation ratio. On November 10, 2017, the Partnership received a waiver from the Administrative Agent and the Lenders of our revolving credit facility waiving the noncompliance through the earlier of (a) December 15, 2017, or (b) the termination, for any reason, of the Purchase and Sale Agreement, dated November 8, 2017, governing the sale of certain oil and gas properties located in Carter and Love Counties, Oklahoma.

If the transaction contemplated by the Sale Agreement is not timely completed, and we are unable to negotiate an additional waiver of the leverage calculation ratio with the Administrative Agent and the Lenders of our revolving credit facility, we may be deemed in default of the revolving credit facility. In that case, unless we are able to secure financing from another source, our lenders would be entitled to accelerate the amounts owed under the revolving credit facility or foreclose on our oil and natural gas properties, either of which would have a material effect on our business and financial condition.

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 as part of this Quarterly Report:

Exhibit No.	Exhibit Description
10.1+	Purchase and Sale Agreement, dated as of November 8, 2017, among Mid-Con Energy Properties, LLC, as seller, and Exponent Energy III, LLC, as purchaser.
10.2+	Class B Convertible Preferred Unit Purchase Agreement, dated as of November 14, 2017, by and among Mid-Con Energy Partners, LP and the Class B Purchasers named on Schedule A thereto.
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 Principal Financial Officer
32.1+	Section 1350 Certificate of Chief Executive Officer
32.2+	Section 1350 Certificate of Principal 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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	MID-CON ENERGY PARTNERS, LP	
	By:	Mid-Con Energy GP, LLC, its general partner
November 14, 2017	By:	/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead Chief Executive Officer
November 14, 2017	By:	/s/ Sherry L. Morgan Sherry L. Morgan Chief Accounting Officer as principal financial officer