Mid-Con Energy Partners, LP
Form 10-Q
May 02, 2018

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 March 31, 2018

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 May 2, 2018, the registrant had 30,305,628 common units.

TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS

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

- volatility of 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;
- 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;
- future capital requirements and 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, 2017 (“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)

	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$612	$ 1,832
Accounts receivable		
Oil and natural gas sales	5,028	5,262
Other	469	103
Prepaid expenses and other	497	166
Assets held for sale, net	430	2,058
Total current assets	7,036	9,421
Property and equipment		
Oil and natural gas properties, successful efforts method		
Proved properties	352,822	335,796
Unproved properties	397	369
Other property and equipment	427	427
Accumulated depletion, depreciation, amortization and impairment	(141,294)	(129,101)
Total property and equipment, net	212,352	207,491
Other assets	1,947	2,451
Total assets	$221,335	$ 219,363
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$799	$ 593
Related parties	1,406	1,631
Derivative financial instruments	5,652	4,252
Accrued liabilities	384	603
Liabilities related to assets held for sale	—	77
Total current liabilities	8,241	7,156
Derivative financial instruments	1,325	666
Long-term debt	89,238	99,000
Other long-term liabilities	64	70
Asset retirement obligations	16,001	10,249
Commitments and contingencies		
Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	20,819	20,534

Class B convertible preferred units - 9,803,921 and 0 issued and outstanding, respectively	14,468	—
Equity, per accompanying statements		
General partner	(695)	(572)
Limited partners - 30,305,628 and 30,090,463 units issued and outstanding, respectively	71,874	82,260
Total equity	71,179	81,688
Total liabilities, convertible preferred units and equity	$221,335	$ 219,363

See accompanying notes to condensed consolidated financial statements

5

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Operations

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31, 2018	2017
Revenues		
Oil sales	$14,544	$14,955
Natural gas sales	168	396
(Loss) gain on derivatives, net	(3,382)	3,132
Total revenues	11,330	18,483
Operating costs and expenses		
Lease operating expenses	4,801	4,992
Oil and natural gas production taxes	872	802
Impairment of proved oil and natural gas properties	8,751	—
Depreciation, depletion and amortization	3,441	4,869
Dry holes and abandonments of unproved properties	88	—
Accretion of discount on asset retirement obligations	153	108
General and administrative	1,894	1,826
Total operating costs and expenses	20,000	12,597
Loss on sales of oil and natural gas properties, net	(400)	—
(Loss) income from operations	(9,070)	5,886
Other (expense) income		
Interest income	2	3
Interest expense	(1,339)	(1,450)
(Loss) gain on settlements of asset retirement obligations	(11)	3
Total other expense	(1,348)	(1,444)
Net (loss) income	(10,418)	4,442
Less: Distributions to preferred unitholders	1,016	798
Less: General partner's interest in net (loss) income	(123)	53
Limited partners' interest in net (loss) income	$(11,311)	$3,591
Limited partners' interest in net (loss) income per unit		
Basic	$(0.37)	$0.12
Diluted	$(0.37)	$0.11
Weighted average limited partner units outstanding		
Limited partner units (basic)	30,176	29,927
Limited partner units (diluted)	30,176	41,837

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Condensed Consolidated Statements of Cash Flows

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2018	2017
Cash Flows from Operating Activities		
Net (loss) income	$(10,418)	$4,442
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Depreciation, depletion and amortization	3,441	4,869
Debt issuance costs amortization	154	336
Accretion of discount on asset retirement obligations	153	108
Impairment of proved oil and natural gas properties	8,751	—
Dry holes and abandonments of unproved properties	88	—
Loss (gain) on settlements of asset retirement obligations	11	(3)
Cash paid for settlements of asset retirement obligations	(27)	(9)
Mark to market on derivatives		
Loss (gain) on derivatives, net	3,382	(3,132)
Cash settlements paid for matured derivatives	(1,324)	(156)
Cash premiums paid for derivatives	—	(1,274)
Loss on sales of oil and natural gas properties	400	—
Non-cash equity-based compensation	239	165
Changes in operating assets and liabilities		
Accounts receivable	234	427
Other receivables	(280)	233
Prepaids and other	(331)	99
Accounts payable - trade and accrued liabilities	319	617
Accounts payable - related parties	(357)	(1,904)
Net cash provided by operating activities	4,435	4,818
Cash Flows from Investing Activities		
Acquisitions of oil and natural gas properties	(8,899)	(134)
Additions to oil and natural gas properties	(1,465)	(2,167)
Additions to other property and equipment	—	(7)
Proceeds from sales of oil and natural gas properties	1,151	—
Net cash used in investing activities	(9,213)	(2,308)
Cash Flows from Financing Activities		
Proceeds from line of credit	2,000	—
Payments on line of credit	(11,762)	(1,500)
Offering costs	—	(70)
Debt issuance costs	(651)	—
Proceeds from sale of Class B convertible preferred units, net of offering costs	14,971	—
Distributions to Class A convertible preferred units	(1,000)	(500)

Net cash provided by (used in) financing activities	3,558	(2,070)
Net (decrease) increase in cash and cash equivalents	(1,220)	440
Beginning cash and cash equivalents	1,832	2,359
Ending cash and cash equivalents	$612	$2,799

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, 2017	$ (572)	30,091	$82,260	$81,688
Equity-based compensation	—	215	239	239
Distributions to Class A convertible preferred units	—	—	(500)	(500)
Distributions to Class B convertible preferred units	—	—	(200)	(200)
Allocation of value to beneficial conversion feature of Class B convertible preferred units	—	—	686	686
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(285)	(285)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(31)	(31)
Net loss	(123)	—	(10,295)	(10,418)
Balance, March 31, 2018	$ (695)	30,306	$71,874	$71,179

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 and development of producing oil and natural gas properties in North America, with a focus on enhanced oil recovery ("EOR"). Our limited partner units ("common units") are listed under the symbol "MCEP" on the NASDAQ. 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, 2017, 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.

Non-cash Investing and Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
(in thousands)	2018	2017
Non-cash investing information		
Change in oil and natural gas properties - accrued capital expenditures	$132	$89
Change in oil and natural gas properties - accrued acquisition	$(86)	$—
Change in oil and natural gas properties - acquisition deposit paid in prior year	$1,000	$—
Supplemental cash flow information		
Cash paid for interest	$892	$1,118

Note 2. Acquisitions, Divestitures and Assets Held for Sale

Acquisitions

We adopted ASU No. 2017-01, "Business Combinations (Topic 805)" effective January 1, 2018. We now evaluate all acquisitions to determine whether they should be accounted for as a business combination or an asset acquisition. The assets acquired and liabilities assumed in the acquisitions were 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 were included in our unaudited condensed consolidated statements of operations.

Powder River Basin

In January 2018, we acquired multiple oil and natural gas properties located in Campbell and Converse Counties, Wyoming, through two separate transactions collectively referred to as Powder River Basin ("PRB"). The House Creek Sussex Unit ("HCSU") transaction qualified as an asset acquisition and the Pine Tree acquisition was accounted for as a business combination. We acquired Pine Tree for cash consideration of $8.5 million, after preliminary post-closing purchase price adjustments.

The recognized fair values of the Pine Tree assets acquired and liabilities assumed are as follows:

(in thousands)	
Fair value of net assets acquired	
Oil and natural gas properties	$9,380
Total assets acquired	9,380
Fair value of net liabilities assumed	
Asset retirement obligation	862
Net assets acquired	$8,518

The following table presents revenues and expenses of the acquired oil and natural gas properties included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended March 31,	
(in thousands)	2018	2017
Oil and natural gas sales	$ 130	$ —
Expenses[1]	$ 120	$ —

[1] Expenses include LOE, production taxes, accretion and depletion.

Wheatland

In June 2017, we acquired multiple oil and natural gas properties located in Oklahoma and Cleveland Counties, Oklahoma, for cash consideration of $4.0 million, after final post-closing purchase price adjustments.

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	$4,305
Other property and equipment	132
Total assets acquired	4,437
Fair value of net liabilities assumed	
Asset retirement obligation	407
Net assets acquired	$4,030

The following table presents revenues and expenses of the oil and natural gas properties acquired included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended March 31,	
(in thousands)	2018	2017
Oil and natural gas sales	$ 722	$ —
Expenses[1]	$ 547	$ —

[1] Expenses include LOE, production taxes, accretion and depletion.

10

Divestitures

Effective at closing, the operations and cash flows of the following divested properties were eliminated from the ongoing operations of the Partnership and the Partnership has no continuing involvement in these properties. The divestitures did not represent a strategic shift and did not have a major effect on the Partnership's operations or financial results.

Nolan County

In January 2018, we completed the sale of certain oil and natural gas proved properties in Nolan County, Texas, for $1.5 million, prior to post-closing purchase price adjustments. These properties were deemed to meet held-for-sale accounting criteria as of December 31, 2017, and impairment of $0.3 million was recorded to reduce the carrying value of these assets to their estimated fair value of $1.5 million at December 31, 2017; therefore, no gain or loss was realized on the sale in 2018.

The following table presents revenues and expenses of the divested oil and natural gas properties that were included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended March 31,	
(in thousands)	2018	2017
Oil and natural gas sales	$ —	$ 177
Expenses[(1)]	$ —	$ 179

[(1)] Expenses include LOE, production taxes, accretion and depletion

Southern Oklahoma

In December 2017, we sold the properties located in Southern Oklahoma for cash proceeds, net of expenses, of $21.7 million, prior to final post-closing purchase price adjustments, and recognized a loss of $4.6 million.

The following table presents revenues and expenses of the oil and natural gas properties sold included in the accompanying consolidated statements of operations for the periods presented:

	Three Months Ended March 31,	
(in thousands)	2018	2017
Oil and natural gas sales	$ (5)	$ 2,641
Expenses[(1)]	$ (17)	$ 2,046

[(1)] Expenses include LOE, production taxes, accretion and depletion

Assets Held for Sale

Land in Southern Oklahoma met held-for-sale criteria as of March 31, 2018, and December 31, 2017. The carrying value of $0.4 million was presented in “Assets held for sale, net” in our unaudited condensed consolidated balance sheets.

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”). If an employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding.

The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at March 31, 2018:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,300,538)
Restricted units granted, net of forfeitures	(399,424)
Equity-settled phantom units granted, net of forfeitures	(830,669)
Awards available for future grant	983,369

We recognized $0.2 million of total equity-based compensation expense for both three months ended March 31, 2018, and 2017. 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 three months ended March 31, 2018, we granted 87,832 unrestricted units with an average grant date fair value of $1.79 per unit. During the three months ended March 31, 2017, we granted 25,400 unrestricted units with an average grant date fair value of $2.65 per unit.

Restricted Unit Awards

Restricted units vest over a period of two or three years. As of March 31, 2018, there were no unrecognized compensation costs related to non-vested restricted units.

A summary of our restricted unit awards for the three months ended March 31, 2018, is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2017	6,362	$ 5.42
Units granted	—	—
Units vested	(6,362)	5.42
Units forfeited	—	—
Outstanding at March 31, 2018	—	$ —

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a period of two or three years 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 three months ended March 31, 2018, we granted 381,000 equity-settled phantom units with a two-year vesting period and 8,500 equity-settled phantom units with a three-year vesting period. During the three months ended March 31, 2017, we granted 9,000 equity-settled phantom units with a three-year vesting period. As of March 31, 2018, there were $0.7 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 twenty-two months.

A summary of our equity-settled phantom unit awards for the three months ended March 31, 2018, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2017	117,495	$ 1.45
Units granted	389,500	1.75
Units vested	(127,333)	1.75
Units forfeited	—	—
Outstanding at March 31, 2018	379,662	$ 1.66

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. 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 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 March 31, 2018, and at December 31, 2017, our commodity derivative contracts were in a net liability position with a fair value of $7.0 million and $4.9 million, respectively. 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 March 31, 2018, 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 March 31, 2018, and December 31, 2017:

(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
March 31, 2018			
Assets			
Derivative financial instruments - current asset	$ 20	$ (20)	$ —
Total	20	(20)	—
Liabilities			
Derivative financial instruments - current liability	(5,271)	(381)	(5,652)

Derivative deferred premium - current liability	(401)	401	—
Derivative financial instruments - long-term liability	(1,325)	—	(1,325)
Total	(6,997)	20	(6,977)
Net Liability	$ (6,977)	$ —	$ (6,977)

(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheets	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheets
December 31, 2017			
Assets			
Derivative financial instruments - current asset	$ 39	$ (39)	$ —
Total	39	(39)	—
Liabilities			
Derivative financial instruments - current liability	(3,890)	(362)	(4,252)
Derivative deferred premium - current liability	(401)	401	—
Derivative financial instruments - long-term liability	(666)	—	(666)
Total	(4,957)	39	(4,918)
Net Liability	$ (4,918)	$ —	$ (4,918)

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

(in thousands)	Three Months Ended March 31, 2018	2017
Net settlements on matured derivatives[1]	$(1,324)	$(156)
Net change in fair value of derivatives	(2,058)	3,288
Total (loss) gain on derivatives, net	$(3,382)	$3,132

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

At March 31, 2018, and December 31, 2017, our commodity derivative contracts had maturities at various dates through September 2020 and were comprised of commodity price swap, put and collar contracts. At March 31, 2018, we had the following oil derivatives net positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index

Swaps - 2018	$ 53.45	$ —	$ —	513	WTI
Puts - 2018	$ —	$ 45.00	$ —	218	WTI
Collars - 2018	$ —	$ 44.13	$ 54.79	1,255	WTI
Swaps - 2019	$ 56.14	$ —	$ —	1,779	WTI
Swaps - 2020	$ 54.81	$ —	$ —	1,199	WTI

At December 31, 2017, we had the following oil derivatives net positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2018	$ 51.33	$ —	$ —	444	WTI
Puts - 2018	$ —	$ 45.00	$ —	164	WTI
Collars - 2018	$ —	$ 44.38	$ 55.52	1,315	WTI
Swaps - 2019	$ 51.48	$ —	$ —	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 for the three months ended March 31, 2018, and for the year ended December 31, 2017.

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 three months ended March 31, 2018, and for the year ended December 31, 2017.

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 March 31, 2018, and December 31, 2017:

(in thousands)	Level 1	Level 2	Level 3	Fair Value
March 31, 2018				
Derivative financial instruments - asset	$ —	$20	$—	$20
Derivative financial instruments - liability	$ —	$6,596	$—	$6,596
Derivative deferred premiums - liability	$ —	$—	$401	$401
December 31, 2017				
Derivative financial instruments - asset	$ —	$39	$—	$39
Derivative financial instruments - liability	$ —	$4,556	$—	$4,556
Derivative deferred premiums - liability	$ —	$—	$401	$401

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

(in thousands)	Three Months Ended March 31, 2018	Year Ended December 31, 2017
Balance of Level 3 at beginning of period	$ (401)	$ (5,449)
Derivative deferred premiums - settlements	—	5,048
Balance of Level 3 at end of period	$ (401)	$ (401)

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% because we believe this amount 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 oil and natural gas assets 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 March 31, 2018, we recorded non-cash impairment of $8.8 million. There were no impairment charges for the three months ended March 31, 2017

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 March 31, 2018, and December 31, 2017, 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:

(in thousands)	Three Months Ended March 31, 2018	Year Ended December 31, 2017
Asset retirement obligations - beginning of period	$ 10,326	$ 11,331
Liabilities incurred for new wells and interest	5,623	759
Liabilities settled upon plugging and abandoning wells	(16)	(57)
Liabilities removed upon sale of wells	(77)	(2,152)
Revision of estimates	(8)	(75)
Accretion expense	153	520
Asset retirement obligations - end of period	$ 16,001	$ 10,326

Note 7. Debt

We had outstanding borrowings under our revolving credit facility of $89.2 million and $99.0 million at March 31, 2018, and December 31, 2017, respectively. Our current revolving credit facility matures in November 2020.

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 1.75% 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 2.75% to 3.75% per annum according to the borrowing base usage. For the three months ended March 31, 2018, the average effective rate was 4.91%. Any unused portion of the borrowing base will be subject to a commitment fee of 0.50% per annum. Letters of credit are subject to a letter of credit fee that varies from 2.75% to 3.75% according to 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.

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.

During the quarter ended September 30, 2017, we were not in compliance with our leverage ratio calculation. 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 December 15, 2017. On December 22, 2017, Amendment 11 to the credit agreement was finalized. The amendment extended the waiver of the leverage ratio default until January 31, 2018. This amendment decreased the Partnership's borrowing base to $115.0 million effective December 22, 2017, and required the facility usage not exceed $100.0 million. The amendment also required that the cash proceeds received from the Southern Oklahoma divestiture on December 22, 2017, and the Nolan County divestiture on January 9, 2018, be applied to the borrowings outstanding. See Note 2 in this section for more information regarding these divestitures.

On January 31, 2018, Amendment 12 to the credit agreement was executed, extending the maturity of our credit facility from November 2018 until November 2020 and increasing the borrowing base of the Partnership's revolving credit facility to $125.0 million. The lenders also waived any default or event of default that occurred as a result of the Partnership's failure to maintain the required leverage ratios for the quarter ended September 30, 2017. The amendment also required the Partnership to have a minimum liquidity of 20% to make cash distributions to the Preferred Unitholders. As of March 31, 2018, we were in compliance with our financial covenants.

Note 8. Commitments and Contingencies

Leases

We lease corporate office space in Tulsa, Oklahoma and Abilene, Texas. Total lease expenses were $0.1 million each for the three months ended March 31, 2018, and 2017. 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 2018	$365
2019	413
2020	418
2021	423
Total	$1,619

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 March 31, 2018, and December 31, 2017, the Partnership's equity consisted of 30,305,628 and 30,090,463 common units, respectively, representing 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 Preferred Units agreements described below, the Partnership suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date until the fifth anniversary of the closing date of the Class A Preferred Units purchase agreement, without the consent of a majority of the holders of the outstanding 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. As of March 31, 2018, 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. 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. 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.

Preferred Units

The Partnership has issued two classes of Preferred Units. Per accounting guidance, we were required to allocate a portion of the proceeds from Preferred Units to a 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 of Preferred Units. The beneficial conversion feature is accreted using the effective yield method over the period from the closing date to the effective date of the holder's conversion right.

The holders of our 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 Preferred Units a cumulative, quarterly cash distribution on 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 Preferred Units, in kind (additional Class A or Class B 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.

Prior to August 11, 2021, each holder of Preferred Units has the right, subject to certain conditions, to convert all or a portion of their 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 Preferred Units, the Partnership will pay any distributions (to the extent accrued and unpaid as of the then most recent Preferred Units distribution date) on the converted units in cash.

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 $24.6 million (net of issuance costs of $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 ($18.6 million) and the beneficial conversion feature ($6.0 million). Accretion of the beneficial conversion feature was $0.3 for the three months ended March 31, 2018, and 2017.

At March 31, 2018, the Partnership had accrued $0.5 million for the first quarter 2018 distribution that will be paid in cash in May 2018. The following table summarizes cash distributions paid on our Class A Preferred Units during the three months ended March 31, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2018	July 1, 2017 - December 31, 2017	$ 0.086	$ 1,000

The following table summarizes cash distributions paid on our Class A Preferred Units during the three months ended March 31, 2017:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2017	October 1, 2016 - December 31, 2016	$ 0.043	$ 500

The registration statement registering resales of common units issued or to be issued upon conversion of the Class A Preferred Units was declared effective by the SEC on June 14, 2017.

Class B Preferred Units

On January 31, 2018, we completed a private placement of 9,803,921 Class B Preferred Units for an aggregate offering price of $15.0 million. The Class B Preferred Units were issued at a price of $1.53 per Class B Preferred Unit (the "Class B Unit Purchase Price"). Proceeds from this issuance were used to fund the acquisition of certain oil and natural gas properties located in Campbell and Converse Counties, Wyoming, and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $14.9 million in connection with the issuance of these Class B Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class B Preferred Units ($14.2 million) and the beneficial conversion feature ($0.7 million). Accretion of the beneficial conversion feature was $0.03 million for the three months ended March 31, 2018.

At March 31, 2018, the Partnership had accrued $0.2 million for the prorated first quarter 2018 distribution that will be paid in cash in May 2018.

Under the registration rights agreements, 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 B Preferred Units and have the registration statement declared effective within 180 days after the closing date. As of May 2, 2018, the common units to be issued were pending effectiveness of registration under a previously filed shelf registration statement on Form S-3.

Allocation of Net Income or Loss

Net income or loss is allocated to our general partner in proportion to its pro rata ownership during the period. The remaining net income or loss is allocated to the limited partner unitholders net of Preferred Unit distributions, including accretion of the Preferred Unit beneficial conversion feature. 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 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, along with various third parties with an ownership interest in the same property, are parties to standard oil and natural gas joint operating agreements with our affiliate, Mid-Con Energy Operating. We and those third parties pay Mid-Con Energy Operating overhead associated with operating our properties and for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. The majority of these expenses were 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 March 31,	
(in thousands)	2018	2017
Services agreement	$530	$641
Operating agreements	1,326	1,403
Oilfield services	911	810
	$2,767	$2,854

At March 31, 2018, we had a net payable to our affiliate, Mid-Con Energy Operating, of $1.4 million, comprised of a joint interest billing payable of $1.2 million and a payable for operating services of $0.2 million. At December 31, 2017, we had a net payable to our affiliate, Mid-Con Energy Operating, of $1.6 million, comprised of a joint interest billing payable of $1.4 million and a payable for operating services of $0.2 million. These amounts were included in accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

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.

Note 12. Revenue Recognition

We adopted ASC 606 effective January 1, 2018, using the modified retrospective approach. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Under ASC 605, we followed the sales method of accounting for oil and natural gas sales revenues in which revenues were recognized on our share of actual proceeds from oil and natural gas sold to purchasers. Revenue recognition required for our oil and natural gas sales contracts by ASC 606 does not differ from revenue recognition required under ASC 605 to account for such contracts. Therefore, we concluded that there was no change in our revenue recognition under ASC 606 and the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018, did not result in an adjustment to retained earnings.

Revenue from Contracts with Customers

Under our oil and natural gas sales contracts, enforceable rights and obligations arise at the time production occurs on dedicated leases as the Partnership promises to deliver goods in the form of oil or natural gas production on contractually-specified leases to the purchasers. Sales of oil and natural gas are recognized at the point that control of the product is transferred to the customer; title and risk of loss to the product generally transfers at the delivery point specified in the contract. The Partnership commits and dedicates for sale all of the crude oil or natural gas production from contractually agreed-upon leases to the purchaser. Our oil contract pricing provisions are tied to a market index, with certain marketing adjustments, including location and quality differentials as well as certain embedded marketing fees. Our natural gas sales revenues are a percentage of the proceeds received by the purchaser for selling the volume of gas produced by the Partnership on a monthly basis. The purchaser sells the volume of natural gas at index rates per Mcf.

Transaction Price Allocated to Remaining Performance Obligations

Our product sales are generally short-term in nature, with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14, exempting the Partnership from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

We have utilized the practical expedient in ASC 606-10-50-14(a), which states the Partnership is not required to disclose the transaction price allocated to remaining performance obligations for specific situations in which the Partnership does not need to estimate variable consideration to recognize revenue. For our crude oil sales and natural gas sales contracts, the variable consideration related to variable production in not estimated because the uncertainty related to the consideration is resolved as the barrels of oil and Mcf of natural gas are transferred to the customer each day.

Contract Balances

Our product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Note 13. Subsequent Events

Distributions

The Board declared Preferred Unit distributions for the first quarter of 2018, according to terms outlined in the Partnership Agreement. Distributions will be paid on May 15, 2018, to holders of record as of the close of business on May 7, 2018. The Class A Preferred Unit cash distributions will be $0.043 per Class A Preferred Unit, or $0.5 million in aggregate. Additionally, the Class B Preferred Unit cash distributions will be $0.020 per Class B Preferred Unit, or

$0.2 million in aggregate for the prorated period.

Class B Preferred Unit Shelf Registration

On May 1, 2018, we filed a shelf registration statement on Form S-3, registering resales of common units issued or to be issued upon conversion of the Class B Preferred Units.

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 limited partnership formed in July 2011 that engages in the ownership, acquisition and development of producing oil and natural gas properties in North America, with a focus on EOR. Our properties are located in Oklahoma, Texas and Wyoming. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Executive Summary - First Quarter 2018

Operating Performance

- In the first quarter, the Partnership drilled one producing well, drilled one injection well, performed six recompletions and eight capital workovers and converted two producing wells to injection.
- Development of waterfloods in our Oklahoma properties continue to show positive response and further development is planned for the remainder of 2018.
- Positive initial waterflood response was observed in 2017 at two Texas properties as a result of new injection. The waterflood developments were expanded in the first quarter of 2018 with continued positive response.
- The Partnership acquired properties in the Powder River Basin in Wyoming. Since acquiring HCSU, fourteen wells were returned to active status with a positive impact on unit production. The Partnership plans to return additional wells to production throughout 2018. At Pine Tree, nine wells were returned to active status and the Partnership is seeking regulatory approval to commence waterflood operations.

Reduction of Debt

As of May 2, 2018, we had reduced debt outstanding by $11.0 million since December 31, 2017. Funds for debt repayment were provided by the Nolan County divestiture, remaining proceeds from the Class B Preferred Unit offering in excess of the PRB acquisition and cash flows from operations.

Distributions

On February 14, 2018, we paid a cash distribution on the Class A Preferred Units of approximately $1.0 million, for the third and fourth quarters of 2017.

Appointment and Departure of Certain Officers

Mr. Philip R. Houchin was appointed as Chief Financial Officer of the general partner effective March 30, 2018.

Business Environment

The markets for oil, natural gas and NGLs 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. Our average sales price per barrel of oil ("Bbl"), excluding commodity derivative contracts, was $61.11 per Bbl and $49.03 per Bbl for the three months ended

March 31, 2018, and 2017, respectively.

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. 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. We have entered oil commodity derivative contracts covering a portion of our anticipated oil production through September 2020.

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 development projects and acquisitions is dependent upon many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and close acquisitions.

We focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flows from operations are impacted by our ability to manage our overall cost structure.

How We Evaluate Our Operations

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which will provide stability and, over time, growth of distributions to our unitholders. The amount of cash that we 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 tables presented in this section summarize certain of the results of operations and period-to-period comparisons for the three months ended March 31, 2018, and 2017. Because of normal production declines, changes in drilling activities, fluctuations in commodity prices and the effects of acquisitions and divestitures, the historical data presented below should not be interpreted as being indicative of future results.

Production and Unit Costs per BOE. The table below provides production volume data and average unit costs per BOE:

	Three Months Ended March 31, 2018	2017	Change	% Change
Production Volumes				
Oil (MBbls)	238	305	(67)	(22 %)
Natural gas (MMcf)	86	124	(38)	(31 %)
Total (MBoe)	252	326	(74)	(23 %)
Average daily net production (Boe/d)	2,800	3,622	(822)	(23 %)
Average sales price				
Oil (per Bbl)				
Sales price	$61.11	$49.03	$12.08	25 %
Effect of net settlements on matured derivative instruments	$(5.56)	$(4.68)	$(0.88)	19 %
Realized oil price after derivatives	$55.55	$44.35	$11.20	25 %
Natural gas (per Mcf)	$1.95	$3.19	$(1.24)	(39 %)
Average unit costs per Boe				
Lease operating expenses	$19.05	$15.31	$3.74	24 %
Oil and natural gas production taxes	$3.46	$2.46	$1.00	41 %
Depreciation, depletion and amortization	$13.65	$14.94	$(1.29)	(9 %)
General and administrative expenses	$7.52	$5.60	$1.92	34 %

Three Months Ended March 31, 2018 Compared with the Three Months Ended March 31, 2017

Operating Revenues. The following table provides oil and natural gas sales data for the three months ended March 31, 2018, and 2017:

(in thousands)	Three Months Ended March 31, 2018	2017	Change	% Change
Oil sales	$14,544	$14,955	$ (411)	(3 %)
Natural gas sales	168	396	(228)	(58 %)
Total oil and natural gas sales	$14,712	$15,351	$ (639)	(4 %)

25

The following table details the change in revenues due to price and volume variances:

(in thousands, except prices)	Change in prices	Production Volumes	Total Net Dollar Effect of Change
Effects of changes in sales price			
Oil (Bbls)	$ 12.08	238	$ 2,875
Natural gas (Mcf)	$ (1.24)	86	(107)
Total revenues due to change in price			2,768
	Change in Production Volumes	Prior Period Average Prices	Total Net Dollar Effect of Change
Effects of production volumes			
Oil (Bbls)	(67)	$ 49.03	$ (3,286)
Natural gas (Mcf)	(38)	$ 3.19	(121)
Total revenues due to change in production volumes			(3,407)
Total change in revenues			$ (639)

The change in oil and natural gas volumes was primarily due to the following:

- divestiture of our Southern Oklahoma properties in December 2017;
- primary production declines at select properties in Texas;
- downtime due to winter weather for certain properties in Oklahoma and Texas;
- production from the June 2017 Wheatland and January 2018 PRB acquisition properties;
- successful new drill results in Texas; and
- positive waterflood responses at key properties located in Oklahoma and Texas.

(Loss) gain on derivatives, net. The table below summarizes the non-cash and cash components of our commodity derivative contracts as well as the change for the three months ended March 31, 2018, and 2017:

	Three Months Ended March 31,			
(in thousands)	2018	2017	Change	% Change
Cash settlements on matured derivatives	$ (1,324)	$ (156)	$ (1,168)	749 %
Non-cash change in fair value of derivatives	(2,058)	3,288	(5,346)	(163 %)
Total (loss) gain on derivatives, net	$ (3,382)	$ 3,132	$ (6,514)	(208 %)

Production expenses. The following table summarizes the change in oil and natural gas production expense for the three months ended March 31, 2018, and 2017:

	Three Months Ended March 31,			
(in thousands)	2018	2017	Change	% Change
Lease operating expenses	$4,801	$4,992	$ (191)	(4 %)
Oil and natural gas production taxes	872	802	70	9 %
Total oil and natural gas production expenses	$5,673	$5,794	$ (121)	(2 %)
Effective production tax rate	5.9 %	5.2 %	0.7 %	13 %

The change in production expenses was primarily due to the following:

- divestiture of our Southern Oklahoma properties in December 2017;
- incremental costs associated with properties acquired in the Wheatland and PRB acquisitions;
- non-routine workover costs for select properties in Texas; and
- discontinuation of the EOR tax credit at one of our Oklahoma units effective July 1, 2017.

The following table summarizes production expenses per Boe data for the three months ended March 31, 2018, and 2017:

(per Boe)	Three Months Ended March 31, 2018	2017	Change	% Change
Lease operating expenses	$19.05	$15.31	$ 3.74	24 %
Oil and natural gas production taxes	3.46	2.46	1.00	41 %
Total oil and natural gas production expenses per Boe	$22.51	$17.77	$ 4.74	27 %

The change in production expenses per Boe was primarily due to:

- lower production volumes in 2018; and
- discontinuation of the EOR tax credit at one of our Oklahoma units effective July 1, 2017.

Depreciation, Depletion, Amortization and Impairment Expenses. The following table provides our non-cash depreciation, depletion and amortization ("DD&A") and impairment expense for the three months ended March 31, 2018, and 2017:

(in thousands)	Three Months Ended March 31, 2018	2017	Change	% Change
Depreciation, depletion and amortization	$3,441	$4,869	$(1,428)	(29 %)
Impairment	8,751	—	8,751	100 %
Total DD&A and impairment	$12,192	$4,869	$7,323	150 %

The change in DD&A was primarily due to:

- decrease in depletion rates due to increased reserves;
- reduced asset carrying values due to impairment in 2017;
- decrease in production volumes; and
- the net impact of the Southern Oklahoma divestiture and the Wheatland and PRB acquisitions.

Impairment of proved oil and natural gas properties was primarily due to persistent wellbore issues on Liberty properties in Texas.

General and Administrative Expenses. The following table provides components of our general and administrative ("G&A") for the three months ended March 31, 2018, and 2017:

Three Months Ended

	March 31,			
(in thousands, except for per Boe)	2018	2017	Change	% Change
General and administrative expenses	$1,655	$1,661	$ (6)	(0 %)
Non-cash compensation	239	165	74	45 %
Total general and administrative expenses	$1,894	$1,826	$ 68	4 %
General and administrative expenses (per Boe)	$7.52	$5.60	1.92	34 %

The change in G&A was primarily due to the issuance of more equity awards in 2018.

Interest Expense. Interest expense is impacted by our borrowings outstanding, interest rates, commitment fees and related debt placement fees which are amortized over the life of the credit agreement. The following table sets forth interest expense for the three months ended March 31, 2018, and 2017:

	Three Months Ended March 31,			
(in thousands)	2018	2017	Change	% Change
Interest expense	$1,339	$1,450	$(111)	(8%)
Average effective interest rate	4.91%	3.56%	1.35%	38%

The change in interest expense was primarily due to:

- lower outstanding borrowings; offset by a
- higher effective interest rate caused by an increase in the underlying market rate and an increase in margins per Amendment 12 to our revolving credit facility.

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 (including regional price differentials), 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. Our primary cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of LOE and G&A. Additionally, in the third quarter 2015, we indefinitely suspended our quarterly cash distributions on common units.

Our liquidity position at May 2, 2018, consisted of approximately $0.8 million of available cash and $36.0 million of available borrowings. Our borrowing base is redetermined in the spring and fall of each year.

Revolving Credit Facility

On January 31, 2018, Amendment 12 to the credit agreement was executed, extending the maturity of our credit facility from November 2018 until November 2020 and increasing the borrowing base of the Partnership’s revolving credit facility to $125.0 million as of January 31, 2018. The lenders also waived any default or event of default that occurred as a result of the Partnership’s failure to maintain the required leverage ratio for the quarter ended September 30, 2017. The amendment also required the Partnership to have a minimum liquidity of 20% to make cash distributions to the Preferred Unitholders. At May 2, 2018, the outstanding borrowings of our revolving credit facility were $88.0 million.

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.

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 2018 for the development, growth and maintenance of our oil and natural gas properties to be $9.7 million. We will adjust our capital program in response to business conditions and operating results along with our evaluation of additional development opportunities that are identified throughout the year.

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. 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 March 31, 2018, we had commodity derivative contracts covering approximately 70%, 63% and 43%, respectively, of our estimated 2018, 2019 and 2020 average daily production (estimate calculated based on the mid-point of our full year 2018 Boe production guidance as released on February 28, 2018, and multiplied by a 94% oil weighting based on first quarter 2018 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 March 31, 2018, we have issued $25.0 million of Class A Preferred Units and $15.0 million of Class B Preferred Units through private placements in August 2016 and January 2018, respectively. Both classes of Preferred Units receive a cumulative, quarterly cash distribution on 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 Preferred Units, in kind (additional Class A or Class B 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 Agreements. See Note 9 to the unaudited condensed consolidated financial statements for additional information regarding Preferred Units.

Sources and Uses of Cash

The following table summarizes the net increase (decrease) in cash for the three months ended March 31, 2018, and 2017:

	Three Months Ended March 31,			
(in thousands)	2018	2017	Change	% Change
Net cash provided by operating activities	$4,435	$4,818	$(383)	(8%)
Net cash used in investing activities	(9,213)	(2,308)	(6,905)	299%
Net cash provided by (used in) financing activities	3,558	(2,070)	5,628	272%

Net (decrease) increase in cash and cash equivalents	$(1,220)	$440	$(1,660)	(377 %)

Operating Activities. The decrease in operating cash flows for the periods compared was primarily attributable to lower oil production volumes.

Investing Activities. During the three months ended March 31, 2018, our cash flow investing activities included:

- the acquisition of oil and natural gas properties in Wyoming for $8.9 million;
- drilling and completion activities of $1.5 million; less
- net proceeds of $1.2 million from the sales of oil and natural gas properties.

During the three months ended March 31, 2017, our cash flow investing activities included:

- drilling and completion activities of $2.2 million; and
- the acquisition of oil and natural gas properties for $0.1 million in Oklahoma.

29

Financing Activities. During the three months ended March 31, 2018, our financing cash flow activities included:

- proceeds of $15.0 million from the issuance of Class B Preferred Units;
- payments of $11.8 million on the revolving credit facility;
- proceeds of $2.0 million from the revolving credit facility;
- distributions of $1.0 million to preferred unitholders; and
- payments of $0.7 million for debt issuance costs.

During the three months ended March 31, 2017, our financing cash flow activities included:

- payments of $1.5 million on the revolving credit facility; and
- distributions of $0.5 million to Class A preferred unitholders.

Off–Balance Sheet Arrangements

As of March 31, 2018, 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

As a smaller reporting company, we are not required to provide the information otherwise required by this item.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our chief executive officer (principal executive officer) and chief financial officer (principal financial officer), the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of March 31, 2018. 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 March 31, 2018, 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.

30

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

There have been no material changes with respect to the risk factors disclosed in our Annual Report for the year ended December 31, 2017.

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

During the three months ended March 31, 2018, we issued $15.0 million of Class B Convertible Preferred Units. See Note 9 to our unaudited condensed consolidated financial statements in this Quarterly Report for additional information regarding this transaction. The Preferred Units were issued in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended (the “Securities Act”), pursuant to Section 4(a)(2) thereof, as a transaction by an issuer not involving any public offering.

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
31.1+	Rule 13a-14(a)/ 15(d)- 14(a) Certification of Chief Executive Officer
31.2+	Rule 13a-14(a)/ 15(d)- 14(a) Certification of Chief Financial Officer
32.1+	Section 1350 Certificate of Chief Executive Officer
32.2+	Section 1350 Certificate of Chief Financial Officer
101.INS+	XBRL Instance Document
101.SCH+	XBRL Taxonomy Extension Schema Document
101.CAL+	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF+	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB+	XBRL Taxonomy Extension Label Linkbase Document
101.PRE+	XBRL Taxonomy Extension Presentation Linkbase Document

+Filed herewith

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
May 2, 2018	By:	/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead Chief Executive Officer
May 2, 2018	By:	/s/ Philip R. Houchin Philip R. Houchin Chief Financial Officer