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 June 30, 2019

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)

Securities Registered pursuant to Section 12(b) of the Act:

Title of each class	Ticker symbol(s)	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	MCEP	NASDAQ Global Select Market

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit 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.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	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 July 26, 2019, the registrant had 30,785,958 common units outstanding.

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CAUTIONARY STATEMENT REGARDING 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. 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:

- 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;
- future capital requirements and availability of financing;
- technology and cybersecurity;
- 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;
- compliance with NASDAQ listing requirements;
- developments in oil and natural gas producing countries; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 1. "Financial Statements," Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Form 10-Q. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," "goal," "forecast," "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, 2018 ("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.

PART I
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Balance Sheets
(in thousands, except number of units)
(Unaudited)

	June 30, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 525	$ 467
Accounts receivable	6,438	4,194
Derivative financial instruments	—	5,666
Prepaid expenses	393	118
Assets held for sale, net	430	430
Total current assets	7,786	10,875
Property and equipment		
Oil and natural gas properties, successful efforts method		
Proved properties	256,654	379,441
Unproved properties	3,476	2,928
Other property and equipment	1,456	427
Accumulated depletion, depreciation, amortization and impairment	(71,686)	(175,948)
Total property and equipment, net	189,900	206,848
Derivative financial instruments	955	2,418
Other assets	1,186	1,563
Total assets	$ 199,827	$ 221,704
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 693	$ 141
Related parties	3,320	3,732
Derivative financial instruments	1,086	—
Accrued liabilities	632	2,024
Other current liabilities	415	—
Total current liabilities	6,146	5,897
Long-term debt	66,000	93,000
Other long-term liabilities	675	47
Asset retirement obligations	30,082	26,001
Commitments and contingencies		
Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	22,325	21,715
Class B convertible preferred units - 9,803,921 issued and outstanding, respectively	14,731	14,635
Equity, per accompanying statements		
General partner	(771)	(786)
Limited partners - 30,785,958 and 30,436,124 units issued and outstanding, respectively	60,639	61,195
Total equity	59,868	60,409
Total liabilities, convertible preferred units and equity	$ 199,827	$ 221,704

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Statements of Operations
(in thousands, except per unit data)
(Unaudited)

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Revenues				
Oil sales	$ 16,792	$ 15,931	$ 31,386	$ 30,475
Natural gas sales	397	264	647	432
Other operating revenues	340	—	712	—
Gain (loss) on derivatives, net	3,396	(9,500)	(8,802)	(12,882)
Total revenues	20,925	6,695	23,943	18,025
Operating costs and expenses				
Lease operating expenses	7,587	5,009	14,417	9,649
Production and ad valorem taxes	1,469	1,205	2,751	2,238
Other operating expenses	417	—	890	—
Impairment of proved oil and natural gas properties	204	959	204	9,710
Depreciation, depletion and amortization	2,369	3,393	5,467	6,834
Dry holes and abandonments of unproved properties	—	97	—	185
Accretion of discount on asset retirement obligations	417	191	745	344
General and administrative	2,348	1,358	5,010	3,252
Total operating costs and expenses	14,811	12,212	29,484	32,212
Gain (loss) on sales of oil and natural gas properties, net	223	12	9,692	(388)
Income (loss) from operations	6,337	(5,505)	4,151	(14,575)
Other (expense) income				
Interest income	1	—	9	2
Interest expense	(1,229)	(1,410)	(2,844)	(2,749)
Other income	44	—	49	—
(Loss) gain on settlements of asset retirement obligations	(56)	60	(56)	49
Total other expense	(1,240)	(1,350)	(2,842)	(2,698)
Net income (loss)	5,097	(6,855)	1,309	(17,273)
Less: Distributions to preferred unitholders	1,157	1,139	2,306	2,155
Less: General partner's interest in net income (loss)	60	(81)	15	(204)
Limited partners' interest in net income (loss)	$ 3,880	$ (7,913)	$ (1,012)	$ (19,224)
Limited partners' interest in net income (loss) per unit				
Basic	$ 0.13	$ (0.26)	$ (0.03)	$ (0.64)
Diluted	$ 0.07	$ (0.26)	$ (0.03)	$ (0.64)
Weighted average limited partner units outstanding				
Limited partner units (basic)	30,786	30,306	30,708	30,241
Limited partner units (diluted)	53,187	30,306	30,708	30,241

See accompanying notes to condensed consolidated financial statements

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

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Cash flows from operating activities		
Net income (loss)	$ 1,309	$ (17,273)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation, depletion and amortization	5,467	6,834
Debt issuance costs amortization	356	329
Accretion of discount on asset retirement obligations	745	344
Impairment of proved oil and natural gas properties	204	9,710
Dry holes and abandonments of unproved properties	—	185
Loss (gain) on settlements of asset retirement obligations	56	(49)
Cash paid for settlements of asset retirement obligations	(72)	(65)
Mark to market on derivatives		
Loss on derivatives, net	8,802	12,882
Cash settlements paid for matured derivatives, net	(586)	(3,505)
(Gain) loss on sales of oil and natural gas properties	(9,692)	388
Non-cash equity-based compensation	456	367
Changes in operating assets and liabilities		
Accounts receivable	(2,441)	(325)
Prepaid expenses and other assets	(254)	(1,565)
Accounts payable - trade and accrued liabilities	434	442
Accounts payable - related parties	(293)	1,277
Net cash provided by operating activities	4,491	9,976
Cash flows from investing activities		
Acquisitions of oil and natural gas properties	(3,262)	(9,257)
Additions to oil and natural gas properties	(5,085)	(3,724)
Proceeds from sales of oil and natural gas properties	32,514	1,163
Net cash provided by (used in) investing activities	24,167	(11,818)
Cash flows from financing activities		
Proceeds from line of credit	7,000	7,000
Payments on line of credit	(34,000)	(19,000)
Debt issuance costs	—	(651)
Proceeds from sale of Class B convertible preferred units, net of offering costs	—	14,878
Distributions to Class A convertible preferred units	(1,000)	(1,500)
Distributions to Class B convertible preferred units	(600)	(200)
Net cash (used in) provided by financing activities	(28,600)	527
Net increase (decrease) in cash and cash equivalents	58	(1,315)
Beginning cash and cash equivalents	467	1,832
Ending cash and cash equivalents	$ 525	$ 517

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, 2018	$ (786)	30,436	$ 61,195	$ 60,409
Equity-based compensation	—	350	334	334
Distributions to Class A convertible preferred units	—	—	(500)	(500)
Distributions to Class B convertible preferred units	—	—	(300)	(300)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(301)	(301)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(48)	(48)
Net loss	(45)	—	(3,743)	(3,788)
Balance, March 31, 2019	(831)	30,786	56,637	55,806
Equity-based compensation	—	—	122	122
Distributions to Class A convertible preferred units	—	—	(500)	(500)
Distributions to Class B convertible preferred units	—	—	(300)	(300)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(309)	(309)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(48)	(48)
Net income	60	—	5,037	5,097
Balance, June 30, 2019	$ (771)	30,786	$ 60,639	$ 59,868
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
Equity-based compensation	—	—	128	128
Distributions to Class A convertible preferred units	—	—	(500)	(500)
Distributions to Class B convertible preferred units	—	—	(300)	(300)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(292)	(292)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(47)	(47)
Net loss	(81)	—	(6,774)	(6,855)
Balance, June 30, 2018	$ (776)	30,306	$ 64,089	$ 63,313

See accompanying notes to 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, 2018, 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

The unaudited condensed consolidated statements of operations for the prior year includes reclassifications from lease operating expenses ("LOE") to production and ad valorem taxes to conform to the current presentation. Such reclassifications have no impact on previously reported net loss.

Non-cash Investing and Supplemental Cash Flow Information

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

(in thousands)	Six Months Ended June 30, 2019	2018
Non-cash investing information		
Change in oil and natural gas properties - assets received in exchange	$ 38,533	$ —
Change in oil and natural gas properties - accrued capital expenditures	$ (74)	$ 238
Change in oil and natural gas properties - accrued acquisitions	$ (1,428)	$ —
Change in oil and natural gas properties - acquisition deposit paid in prior year	$ —	$ 1,000
Supplemental cash flow information		
Cash paid for interest	$ 2,619	$ 2,153

Note 2. Acquisitions, Divestitures and Assets Held for Sale

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 business combinations or asset acquisitions. The guidance provides 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. If the screen is not met, to be considered a business, the set must include an input and substantive process that together significantly contribute to the ability to create output.

Assets and liabilities assumed in acquisitions accounted for as business combinations 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.

The operations and cash flows of divested properties are eliminated from our ongoing operations.

Pine Tree Business Combination

In January 2018, we acquired multiple oil and natural gas properties located in Campbell and Converse Counties, Wyoming (the “Pine Tree” acquisition). Pine Tree was accounted for as a business combination. We acquired Pine Tree for cash consideration of $8.4 million, after final 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		
Proved oil and natural gas properties	$	8,833
Total assets acquired		8,833
Fair value of net liabilities assumed		
Asset retirement obligation		463
Net assets acquired	$	8,370

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

	Three Months Ended June 30,				**Six Months Ended June 30,**			
(in thousands)	**2019**		**2018**		**2019**		**2018**	
Oil and natural gas sales	$	481	$	354	$	703	$	484
Expenses(1)	$	356	$	161	$	564	$	281

(1) Expenses include LOE, production and ad valorem taxes, accretion and depletion.

Strategic Transaction

In March 2019, we simultaneously closed the previously announced definitive agreements to sell substantially all of our oil and natural gas properties located in Texas for $60.0 million and to purchase certain oil and natural gas properties located in Osage, Grady and Caddo Counties in Oklahoma for an aggregate purchase price of $27.5 million, both agreements subject to customary purchase price adjustments. We received net proceeds of $32.5 million at the close of this Strategic Transaction (“Strategic Transaction”) of which $32.0 million was used to reduce borrowings outstanding on our revolving credit facility. The acquired properties were accounted for as an asset acquisition. A gain on the sale of oil and natural gas properties of $9.5 million was reported in the unaudited condensed consolidated statements of operations.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Oil and natural gas sales	$ 39	$ 6,898	$ 4,689	$ 13,866
Expenses[1]	$ (4)	$ 5,301	$ 3,370	$ 9,719

(1) Expenses include LOE, production and ad valorem taxes, impairment of proved oil and natural gas properties, dry hole and abandonment, accretion and depletion.

Nolan County Divestiture

In January 2018, we completed the sale of certain oil and natural gas proved properties in Nolan County, Texas, for $1.5 million, after final 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.

Assets Held for Sale

Land in Southern Oklahoma met held-for-sale criteria as of June 30, 2019, and December 31, 2018. The carrying value of $0.4 million was presented as “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 June 30, 2019:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,350,538)
Restricted units granted, net of forfeitures	(399,424)
Equity-settled phantom units granted, net of forfeitures	(1,490,669)
Awards available for future grant	273,369

We recognized $0.1 million and $0.4 million of total equity-based compensation expense for the three months and six months ended June 30, 2019, respectively. We recognized $0.1 million and $0.3 million of total equity-based compensation expense for the three months and six months ended June 30, 2018, 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 six months ended June 30, 2019, we granted 50,000 unrestricted units with an average grant date fair value of $1.04 per unit. During the six months ended June 30, 2018, we granted 87,832 unrestricted units with an average grant date fair value of $1.79 per unit.

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a period of two or three years. During the six months ended June 30, 2019, we granted 510,000 equity-settled phantom units with a two-year vesting period and 63,000 equity-settled phantom units with a three-year vesting period. During the six months ended June 30, 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. As of June 30, 2019, there were $0.6 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 seventeen months.

A summary of our equity-settled phantom unit awards for the six months ended June 30, 2019, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2018	351,166	$ 1.73
Units granted	573,000	1.04
Units vested	(299,834)	1.35
Units forfeited	(15,000)	1.60
Outstanding at June 30, 2019	609,332	$ 1.27

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 (commodity price and differential 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 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 June 30, 2019, our commodity derivative contracts were in a net liability position with a fair value of $0.1 million, whereas at December 31, 2018, our commodity derivative contracts were in a net asset position with a fair value of $8.1 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 June 30, 2019, 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 June 30, 2019, and December 31, 2018:

(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
June 30, 2019			
Assets			
Derivative financial instruments - current asset	$ 67	$ (67)	$ —
Derivative financial instruments - long-term asset	2,369	(1,414)	955
Total	2,436	(1,481)	955
Liabilities			
Derivative financial instruments - current liability	(1,153)	67	(1,086)
Derivative financial instruments - long-term liability	(1,414)	1,414	—
Total	(2,567)	1,481	(1,086)
Net liability	$ (131)	$ —	$ (131)

(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, 2018			
Assets			
Derivative financial instruments - current asset	$ 5,705	$ (39)	$ 5,666
Derivative financial instruments - long-term asset	2,418	—	2,418
Total	8,123	(39)	8,084
Liabilities			
Derivative financial instruments - current liability	(39)	39	—
Total	(39)	39	—
Net asset	$ 8,084	$ —	$ 8,084

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Net settlements on matured derivatives(1)	$ (729)	$ (2,181)	$ (586)	$ (3,505)
Net change in fair value of derivatives	4,125	(7,319)	(8,216)	(9,377)
Total gain (loss) on derivatives, net	$ 3,396	$ (9,500)	$ (8,802)	$ (12,882)

(1) The settlement amount does not include premiums paid attributable to contracts that matured during the respective period.

At June 30, 2019, and December 31, 2018, our commodity derivative contracts had maturities at various dates through December 2021 and were comprised of commodity price and differential swaps and collar contracts. At June 30, 2019, we had the following oil derivatives net positions:

Period Covered	Differential Fixed Price	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	Index
Swaps - 2019	$ —	$ 56.08	$ —	$ —	1,692	NYMEX-WTI
Swaps - 2019	$ (20.15)	$ —	$ —	$ —	150	WCS-CRUDE-OIL
Swaps - 2020	$ —	$ 55.81	$ —	$ —	1,931	NYMEX-WTI
Swaps - 2021	$ —	$ 55.78	$ —	$ —	672	NYMEX-WTI
Collars - 2021	$ —	$ —	$ 52.00	$ 58.80	672	NYMEX-WTI

At December 31, 2018, we had the following oil derivatives net positions:

Period Covered	Differential Fixed Price	Weighted Average Fixed Price	Total Bbls Hedged/day	Index
Swaps - 2019	$ —	$ 56.14	1,779	NYMEX-WTI
Swaps - 2019	$ (20.15)	$ —	137	WCS-CRUDE-OIL
Swaps - 2020	$ —	$ 54.81	1,199	NYMEX-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 and six months ended June 30, 2019, and for the year ended December 31, 2018.

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 and six months ended June 30, 2019, and for the year ended December 31, 2018.

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. Any deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as we utilize 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 fair value of our assets and liabilities measured at fair value on a recurring basis as of June 30, 2019, and December 31, 2018:

(in thousands)	Level 1	Level 2	Level 3	Fair Value
June 30, 2019				
Derivative financial instruments - asset	$ —	$ 2,436	$ —	$ 2,436
Derivative financial instruments - liability	$ —	$ 2,567	$ —	$ 2,567
December 31, 2018				
Derivative financial instruments - asset	$ —	$ 8,123	$ —	$ 8,123
Derivative financial instruments - liability	$ —	$ 39	$ —	$ 39

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

(in thousands)	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Balance of Level 3 at beginning of period	$ —	$ (401)
Derivative deferred premiums - settlements	—	401
Balance of Level 3 at end of period	$ —	$ —

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 our 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 expense is recognized for the difference between the estimated fair value and the carrying value of the assets. We recorded impairment expense of $0.2 million for the three and six months ended June 30, 2019. We recorded impairment expense of $1.0 million and $9.7 million for the three and six months ended June 30, 2018, respectively.

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 June 30, 2019, and December 31, 2018, 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)	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Asset retirement obligations - beginning of period	$ 26,001	$ 10,326
Liabilities incurred for new wells and interest	8,993	15,497
Liabilities settled upon plugging and abandoning wells	(16)	(138)
Liabilities removed upon sale of wells	(5,641)	(399)
Revision of estimates	—	(6)
Accretion expense	745	721
Asset retirement obligations - end of period	$ 30,082	$ 26,001

Note 7. Debt

We had outstanding borrowings under our revolving credit facility of $66.0 million and $93.0 million at June 30, 2019, and December 31, 2018, respectively. Our current revolving credit facility matures in November 2020. Borrowings under the facility are secured by liens on not less than 90% of the value of our proved reserves.

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. The next regularly scheduled redetermination is expected to occur in the fall of 2019.

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 June 30, 2019, the average effective rate was 5.73%. Any unused portion of the borrowing base is 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, and restrictions on certain transactions and payments, including distributions, and requires us to maintain hedges covering projected production. 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.

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 our revolving credit facility to $125.0 million. The lenders also waived any default or event of default that occurred as a result of our failure to maintain the required leverage ratios for the quarter ended September 30, 2017. The amendment also required us to have a minimum liquidity of 20% to make cash distributions to the Preferred Unitholders.

During the fall 2018 semi-annual borrowing base redetermination of our revolving credit facility completed in December 2018, the lender group increased our borrowing base to $135.0 million effective December 19, 2018. There were no changes to the terms or conditions of the credit agreement.

On March 28, 2019, in conjunction with closing the Strategic Transaction and serving as our spring redetermination, Amendment 13 to the credit agreement was executed, decreasing our borrowing base to $110.0 million. The amendment also required that the leverage ratio be calculated on a building, period-annualized basis, beginning the second quarter of 2019. As of June 30, 2019, we were in compliance with our financial covenants. See Note 2 in this section for further discussion of the Strategic Transaction.

Note 8. Commitments and Contingencies

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 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 agreements stipulate 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

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 material legal or governmental proceedings against us under the various environmental protection statutes to which we are subject.

Note 9. Equity

Common Units

At June 30, 2019, and December 31, 2018, the Partnership's equity consisted of 30,785,958 and 30,436,124 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 purchase agreement for the Class A Preferred Units described below, we suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date until August 11, 2021, 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 June 30, 2019, 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. Proceeds from this issuance were used to fund an acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $24.6 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 million and $0.6 million for the three and six months ended June 30, 2019 and 2018, respectively. 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.

At June 30, 2019, the Partnership had accrued $0.5 million for the second quarter 2019 distributions that will be paid in cash in August 2019. The following table summarizes cash distributions paid on our Class A Preferred Units during the six months ended June 30, 2019:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2019	October 1, 2018 - December 31, 2018	$ 0.0430	$ 500
May 14, 2019	January 1, 2019 - March 31, 2019	$ 0.0430	$ 500

The following table summarizes cash distributions paid on our Class A Preferred Units during the six months ended June 30, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2018	July 1, 2017 - December 31, 2017	$ 0.0860	$ 1,000
May 15, 2018	January 1, 2018 - March 31, 2018	$ 0.0430	$ 500

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. 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 $0.1 million for the six months ended June 30, 2019 and 2018. The registration statement registering resales of common units issued or to be issued upon conversion of the Class B Preferred Units was declared effective by the SEC on May 25, 2018.

At June 30, 2019, the Partnership had accrued $0.3 million for the second quarter 2019 distributions that will be paid in cash in August 2019. The following table summarizes cash distributions paid on our Class B Preferred Units during the six months ended June 30, 2019:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2019	October 1, 2018 - December 31, 2018	$ 0.0306	$ 300
May 14, 2019	January 1, 2019 - March 31, 2019	$ 0.0306	$ 300

The following table summarizes cash distributions paid on our Class B Preferred Units during the six months ended June 30, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
May 15, 2018	February 1, 2018 - March 31, 2018	$ 0.0200	$ 200

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 managerial, 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 are included in 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.

Other Agreements

We are party to monitoring fee agreements with Bonanza Fund Management, Inc. ("Bonanza"), a Class A Preferred Unitholder, and Goff Focused Strategies, LLC ("GFS"), a Class B Preferred Unitholder, pursuant to which we pay Bonanza and GFS a quarterly monitoring fee in connection with monitoring the purchasers' investments in the Preferred Units. These expenses are included in G&A in our unaudited condensed consolidated statements of operations.

The following table summarizes the related party transactions for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Services agreement	$ 708	$ 599	$ 1,477	$ 1,129
Operating agreements	2,708	1,465	5,544	2,791
Oilfield services	1,415	1,117	2,512	2,028
Other Agreements	80	80	160	150
	$ 4,911	$ 3,261	$ 9,693	$ 6,098

At June 30, 2019, we had a net payable to our affiliate, Mid-Con Energy Operating, of $3.3 million, comprised of a joint interest billing payable of $5.0 million and a payable for operating services and other miscellaneous items of $0.2 million, offset by an oil and natural gas revenue receivable of $1.9 million. At December 31, 2018, we had a net payable to our affiliate, Mid-Con Energy Operating, of $3.7 million, comprised of a joint interest billing payable of $3.7 million and a payable for operating services and other miscellaneous items of $1.2 million, offset by an oil and natural gas revenue receivable of $1.2 million. These amounts were included in accounts payable-related parties in our unaudited condensed consolidated balance sheets.

Note 11. New Accounting Standards

On January 1, 2019, we adopted ASC 842, *Leases* (“ASC 842”). See Note 13 in this section for further discussion of ASC 842.

In June 2016, the FASB issued ASC 326, *Financial Instruments- Credit Losses* (“ASC 326”), which replaces the current “incurred loss” methodology for recognizing credit losses with an “expected loss” methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. We do not believe this new guidance will have a material impact on our consolidated financial statements.

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. We had no significant natural gas imbalances at June 30, 2019 and 2018.

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. We do not extract natural gas liquids (“NGLs”) from our natural gas production prior to the sale and transfer of title of the natural gas stream to our purchasers. While some of our purchasers extracted NGLs from the natural gas stream sold by us to them, we had no ownership in such NGLs. The Partnership commits and dedicates for sale all of the 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. The majority of our natural gas contract pricing provisions are tied to a market index less customary deductions, such as gathering, processing and transportation. Payment is typically received 30 to 60 days after the date production is delivered.

Transaction Price Allocated to Remaining Performance Obligations

Our oil and natural gas 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.

For our oil and natural gas sales contracts, the variable consideration related to variable production is not estimated because the uncertainty related to the consideration is resolved as the barrel of oil (“Bbl”) and Mcf of natural gas are transferred to the customer each day. Therefore, 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.

Contract Balances

Our oil and natural gas sales contracts do not give rise to contract assets or liabilities under ASC 606.

Note 13. Leases

We adopted ASC 842, as amended, on January 1, 2019, using the modified retrospective approach. The modified retrospective approach provided a method for recording existing leases at adoption and allowed for a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The adoption of this standard did not result in an adjustment to retained earnings. We elected the transition package of practical expedients permitted under the transition guidance, which among other things, allowed us to carry forward the historical lease classification. We also elected the optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840, *Leases* ("ASC 840"). Our leases do not provide an implicit discount rate; therefore, we used our incremental borrowing rate as of January 1, 2019. As a result of adopting the new standard, we recorded lease assets and lease liabilities of $1.2 million and $1.3 million, respectively, as of January 1, 2019.

We lease office space in Tulsa, Oklahoma, Abilene, Texas, and Gillette, Wyoming. Per the short-term accounting policy election, leases with an initial term of 12 months or less were not recorded on the balance sheet, and we recognize lease expense for these leases on a straight-line basis over the term of the lease. Most of our leases include an option to renew. The exercise of the lease renewal options is at our discretion.

A summary of our leases is presented below:

(in thousands)	Classification	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Assets			
Operating	Other property and equipment	$ 1,029	$ —
Total lease assets		$ 1,029	$ —
Liabilities			
Current operating	Other current liabilities	$ 415	$ —
Non-current operating	Other long-term liabilities	675	—
Total lease liabilities		$ 1,090	$ —

	Classification	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Operating lease expense(1)(2) (in thousands)	G&A expense	$ 65	$ 62	$ 131	$ 127
Weighted average remaining lease term (months)					
Operating leases		29	41	29	41
Weighted average discount rate					
Operating leases		5.7%	(3)	5.7%	(3)

(1) Includes short-term leases.
(2) There is not a material difference between cash paid and amortized expense.
(3) Not applicable under ASC 840.

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

(in thousands)	Operating Leases
Remaining 2019	$ 236
2020	469
2021	472
Total lease maturities	1,177
Less: interest	87
Present value of lease liabilities	$ 1,090

Note 14. Subsequent Events

Distributions

On July 29, 2019, the Partnership announced that the Board declared Preferred Unit distributions for the second quarter of 2019, according to terms outlined in the Partnership Agreement. Distributions will be paid on August 14, 2019, to holders of record as of the close of business on August 7, 2019. The Class A Preferred Unit cash distributions will be $0.0430 per Class A Preferred Unit, or $0.5 million in aggregate. Additionally, the Class B Preferred Unit cash distributions will be $0.0306 per Class B Preferred Unit, or $0.3 million in aggregate.

Change in Control Severance Plan

On July 24, 2019, the Board adopted a change in control severance plan that provides severance benefits to certain key management in the event of a change in control.

Appointment and Departure of Certain Officers

On July 24, 2019, the Board appointed Chad B. Roller, Ph.D., as Chief Operating Officer of the general partner.

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 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

Highlights and Recent Developments

- Net income was $5.1 million for the second quarter of 2019.
- Generated positive cash flows from operating activities for the second quarter of 2019 of $5.6 million.
- Continued to reduce outstanding borrowings on our revolving credit facility. Total net reduction of $27.0 million for the six months ended June 30, 2019.
- Increased production of 2% from first quarter of 2019, despite historic flooding in Oklahoma. Production impacted by flooding is expected to be restored during third quarter of 2019.
- Increased cash flow and asset value due to lower than anticipated LOE in newly acquired assets in Oklahoma.
- Achieved first injection in our Wyoming waterflood project. Formal unitization approval expected in third quarter of 2019.
- Returned 50 wells to production in newly acquired assets.

Business Environment

The markets for oil and natural gas 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 Bbl, excluding commodity derivative contracts, was $53.84 and $62.32 for the six months ended June 30, 2019 and 2018, 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 (commodity price and differential 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 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 December 2021.

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; and
- LOE.

Results of Operations

The tables presented in this section summarize certain of the results of operations and period-to-period comparisons for the three and six months ended June 30, 2019 and 2018. 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, Prices and Unit Costs per Boe. The table below provides production volume data, average sales prices and average unit costs per Boe:

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Production Volumes								
Oil (MBbls)	291	251	40	16%	583	489	94	19%
Natural gas (MMcf)	184	92	92	100%	305	178	127	71%
Total (MBoe)	322	267	55	21%	634	519	115	22%
Average daily net production (Boe/d)	3,538	2,934	604	21%	3,503	2,867	636	22%
Average sales price								
Oil (per Bbl)								
Sales price	$ 57.70	$ 63.47	$ (5.77)	(9%)	$ 53.84	$ 62.32	$ (8.48)	(14%)
Effect of net settlements on matured derivative instruments	$ (2.50)	$ (8.69)	$ 6.19	71%	$ (1.01)	$ (7.17)	$ 6.16	86%
Realized oil price after derivatives	$ 55.20	$ 54.78	$ 0.42	1%	$ 52.83	$ 55.15	$ (2.32)	(4%)
Natural gas (per Mcf)	$ 2.16	$ 2.87	$ (0.71)	(25%)	$ 2.12	$ 2.43	$ (0.31)	(13%)
Average unit costs per Boe								
Lease operating expenses	$ 23.56	$ 18.76	$ 4.80	26%	$ 22.74	$ 18.59	$ 4.15	22%
Production and ad valorem taxes	$ 4.56	$ 4.51	$ 0.05	1%	$ 4.34	$ 4.31	$ 0.03	1%
Depreciation, depletion and amortization	$ 7.36	$ 12.71	$ (5.35)	(42%)	$ 8.62	$ 13.17	$ (4.55)	(35%)
General and administrative expenses	$ 7.29	$ 5.09	$ 2.20	43%	$ 7.90	$ 6.27	$ 1.63	26%

Oil and natural gas sales. The following table provides oil and natural gas sales data for the three and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Oil sales	$ 16,792	$ 15,931	$ 861	5%	$ 31,386	$ 30,475	$ 911	3%
Natural gas sales	397	264	133	50%	647	432	215	50%
Total oil and natural gas sales	$ 17,189	$ 16,195	$ 994	6%	$ 32,033	$ 30,907	$ 1,126	4%

The following table details the change in oil and natural gas sales due to price and volume variances:

(in thousands, except prices)	Three Months Ended June 30, 2019 and 2018 — Change in prices	Production Volumes	Total Net Dollar Effect of Change	Six Months Ended June 30, 2019 and 2018 — Change in prices	Production Volumes	Total Net Dollar Effect of Change
Effects of changes in sales price						
Oil (Bbls)	$ (5.77)	291	$ (1,679)	$ (8.48)	583	$ (4,945)
Natural gas (Mcf)	$ (0.71)	184	(131)	(0.31)	305	(95)
Total oil and natural gas sales due to change in price			$ (1,810)			$ (5,040)

	Change in Production Volumes	Prior Period Average Prices	Total Net Dollar Effect of Change	Change in Production Volumes	Prior Period Average Prices	Total Net Dollar Effect of Change
Effects of production volumes						
Oil (Bbls)	40	$ 63.47	$ 2,540	94	$ 62.32	$ 5,856
Natural gas (Mcf)	92	$ 2.87	264	127	$ 2.43	310
Total oil and natural gas sales due to change in production volumes			2,804			6,166
Total change in oil and natural gas sales			$ 994			$ 1,126

The change in oil and natural gas sales for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to:

- incremental production from properties acquired in Oklahoma and Wyoming; offset by
- divestitures of our Texas properties; and
- decreased oil sales prices.

Gain (loss) on derivatives, net. The table below summarizes the cash and non-cash components of our commodity derivative contracts as well as the change for the three and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	2018	Change	% Change	Six Months Ended June 30, 2019	2018	Change	% Change
Cash settlements on matured derivatives, net[1]	$ (729)	$ (2,181)	$ 1,452	67%	$ (586)	$ (3,505)	$ 2,919	83%
Non-cash change in fair value of derivatives	4,125	(7,319)	11,444	156%	(8,216)	(9,377)	1,161	12%
Total gain (loss) on derivatives	$ 3,396	$ (9,500)	$ 12,896	136%	$ (8,802)	$ (12,882)	$ 4,080	32%

(1) The settlement amount does not include premiums paid attributable to contracts that matured during the respective period.

Lease operating expenses. The following table summarizes the change in lease operating expenses for the three and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	2018	Change	% Change	Six Months Ended June 30, 2019	2018	Change	% Change
Lease operating expenses	$ 7,327	$ 4,732	$ 2,595	55%	$ 13,896	$ 9,039	$ 4,857	54%
Workover expenses	260	277	(17)	(6%)	521	610	(89)	(15%)
Total lease operating expenses	$ 7,587	$ 5,009	$ 2,578	51%	$ 14,417	$ 9,649	$ 4,768	49%

The change in lease operating expenses for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to:

- incremental costs associated with properties acquired in Oklahoma and Wyoming; offset by
- divestitures of our Texas properties.

The following table summarizes lease operating expenses per Boe data for the three and six months ended June 30, 2019 and 2018:

(per Boe)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Lease operating expenses	$ 22.75	$ 17.72	$ 5.03	28%	$ 21.92	$ 17.42	$ 4.50	26%
Workover expenses	0.81	1.04	(0.23)	(22%)	0.82	1.17	(0.35)	(30%)
Total lease operating expenses per Boe	$ 23.56	$ 18.76	$ 4.80	26%	$ 22.74	$ 18.59	$ 4.15	22%

The change in lease operating expenses per Boe for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to:

- properties acquired in Oklahoma with higher LOE per Boe; offset by
- divestitures of our Texas properties with lower LOE per Boe.

Production and ad valorem taxes. The following table summarizes the change in production and ad valorem taxes for the three and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Production taxes	$ 1,193	$ 963	$ 230	24%	$ 2,109	$ 1,835	$ 274	15%
Ad valorem taxes	276	242	34	14%	642	403	239	59%
Total production and ad valorem taxes	$ 1,469	$ 1,205	$ 264	22%	$ 2,751	$ 2,238	$ 513	23%

The change in production and ad valorem expenses for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to:

- increased production taxes due to higher production volumes; and
- increased ad valorem taxes due to properties acquired in Wyoming.

The following table summarizes production and ad valorem taxes per Boe data for the three and six months ended June 30, 2019 and 2018:

(per Boe)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Production taxes	$ 3.70	$ 3.60	$ 0.10	3%	$ 3.33	$ 3.53	$ (0.20)	(6%)
Ad valorem taxes	0.86	0.91	(0.05)	(5%)	1.01	0.78	0.23	29%
Total production and ad valorem taxes per Boe	$ 4.56	$ 4.51	$ 0.05	1%	$ 4.34	$ 4.31	$ 0.03	1%

The change in production and ad valorem taxes per Boe for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to the changes noted above and the divestitures of our Texas properties with a lower state oil production tax rate.

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 and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Depreciation, depletion and amortization	$ 2,369	$ 3,393	$ (1,024)	(30%)	$ 5,467	$ 6,834	$ (1,367)	(20%)
Impairment	204	959	(755)	(79%)	204	9,710	(9,506)	(98%)
Total DD&A and impairment expense	$ 2,573	$ 4,352	$ (1,779)	(41%)	$ 5,671	$ 16,544	$ (10,873)	(66%)

The change in DD&A for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to:

- reduced asset carrying values due to impairment in 2018; and
- the net impact of the Texas divestitures and the properties acquired in Oklahoma and Wyoming.

Impairment of proved oil and natural gas properties for the three and six months ended June 30, 2019, was primarily due to reserve revisions. Impairment of proved oil and natural gas properties for the three and six months ended June 30, 2018, was primarily due to persistent wellbore issues on a certain Texas project.

General and administrative expenses. The following table provides components of our G&A for the three and six months ended June 30, 2019 and 2018:

(in thousands, except for per Boe)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
General and administrative expenses	$ 2,226	$ 1,230	$ 996	81%	$ 4,554	$ 2,885	$ 1,669	58%
Non-cash compensation	122	128	(6)	(5%)	456	367	89	24%
Total general and administrative expenses	$ 2,348	$ 1,358	$ 990	73%	$ 5,010	$ 3,252	$ 1,758	54%
General and administrative expenses (per Boe)	$ 7.29	$ 5.09	2.20	43%	$ 7.90	$ 6.27	1.63	26%

The change in both G&A and G&A per Boe for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to increased professional and other fees related to acquisition and divestiture activity.

Gain (loss) on sales of oil and natural gas properties. The following table provides our gain (loss) on sales of oil and natural gas properties for the three and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Gain (loss) on sales of oil and natural gas properties, net	$ 223	$ 12	$ 211	1758%	$ 9,692	$ (388)	$ 10,080	2598%

The change in gain (loss) on sales of oil and natural gas properties for the three and six months ended June 30, 2019, was due to the divestiture of substantially all of our Texas properties as part of the Strategic Transaction. For the three and six months ended June 30, 2018, the gain (loss) on sales of oil and natural gas properties was primarily related to the Southern Oklahoma divestiture.

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 and six months ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Change	% Change	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Change	% Change
Interest expense	$ 1,229	$ 1,410	$ (181)	(13%)	$ 2,844	$ 2,749	$ 95	3%
Average effective interest rate	5.73%	5.21%	0.52%	10%	5.75%	5.05%	0.70%	14%

The change in interest expense for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018, was primarily due to:

- lower outstanding borrowings resulting from the payment of $32.0 million on the revolving credit facility from funds received in conjunction with the Strategic Transaction; offset by
- higher effective interest rate caused by an increase in the underlying market 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 borrow and our ability to raise equity or debt capital. 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 July 26, 2019, consisted of approximately $0.6 million of available cash and $43.0 million of available borrowings ($110.0 million borrowing base less $66.0 million outstanding borrowings and $1.0 million outstanding standby letter of credit). Our borrowing base is redetermined in the spring and fall of each year.

Revolving Credit Facility

On March 28, 2019, in conjunction with closing the Strategic Transaction, Amendment 13 to the credit agreement was executed, decreasing the borrowing base of the Partnership’s revolving credit facility to $110.0 million. The amendment also required that the leverage ratio be calculated on a building, period-annualized basis, beginning the second quarter of 2019. At July 26, 2019, the outstanding balances of our revolving credit facility and standby letter of credit were $66.0 million and $1.0 million, respectively.

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 Preferred Units.

We currently expect capital spending for the remainder of 2019 for the development, growth and maintenance of our oil and natural gas properties to be $5.4 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 (commodity price and differential 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 or as required by our lenders. At June 30, 2019, we had commodity derivative contracts covering approximately 52%, 60% and 41%, respectively, of our estimated 2019, 2020 and 2021 average daily production (estimate calculated based on the mid-point of our full-year 2019 Boe production guidance as released on July 31, 2019, and multiplied by a 90% oil weighting based on second quarter 2019 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 June 30, 2019, 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 change in cash for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,			
(in thousands)	**2019**	**2018**	**Change**	**% Change**
Operating activities				
Net cash provided by operating activities	$ 4,491	$ 9,976	$ (5,485)	(55%)
Investing activities				
Acquisitions of oil and natural gas properties	(3,262)	(9,257)	5,995	65%
Additions to oil and natural gas properties	(5,085)	(3,724)	(1,361)	(37%)
Proceeds from sales of oil and natural gas properties	32,514	1,163	31,351	2696%
Net cash provided by (used in) investing activities	24,167	(11,818)	35,985	304%
Financing activities				
Proceeds from line of credit	7,000	7,000	—	0%
Payments on line of credit	(34,000)	(19,000)	(15,000)	(79%)
Proceeds from sale of Class B convertible preferred units, net of offering costs	—	14,878	(14,878)	(100%)
Other	(1,600)	(2,351)	751	32%
Net cash (used in) provided by financing activities	(28,600)	527	(29,127)	(5527%)
Change in cash and cash equivalents	$ 58	$ (1,315)	$ 1,373	104%

Operating activities. The change in operating cash flows for the periods compared was primarily attributable to:

- increased LOE of $4.8 million;
- increased cash used for working capital of $2.4 million; and
- increased G&A of $1.8 million; offset by
- decreased settlements paid on derivatives of $2.9 million.

Investing and financing activities. The change in investing and financing cash flows for the periods compared was primarily attributable to:

- larger than normal proceeds from the sale of oil and natural gas properties and resulting payments on the revolving credit facility due to the Strategic Transaction. See Note 2 to the unaudited condensed consolidated financial statements for further discussion of the Strategic Transaction; and
- Preferred Units issuance in 2018.

Off–Balance Sheet Arrangements

As of June 30, 2019, 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 June 30, 2019. 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 June 30, 2019, 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 material legal or governmental proceedings 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, 2018.

We may not be able to maintain our listing on the NASDAQ Global Select Market, which could have a material adverse effect on us and our unitholders.

NASDAQ has established certain standards for the continued listing of a security on the NASDAQ Global Select Market. The standards for continued listing include, among other things, that the minimum bid price for the listed securities not fall below $1.00 per share for a period of 30 consecutive days.

On March 26, 2019, the Partnership received a deficiency letter from the Listing Qualifications Department (the "Staff") of the NASDAQ Stock Market notifying the Partnership that, for the last 30 consecutive business days, the bid price for the Partnership's common units had closed below the minimum $1.00 per unit requirement for continued inclusion on the NASDAQ Global Select Market pursuant to NASDAQ Listing Rule 5450(a)(1) (the "Bid Price Rule"). In accordance with NASDAQ rules, the Partnership has been provided an initial period of 180 calendar days, or until September 23, 2019 (the "Compliance Date"), to regain compliance with the Bid Price Rule. If, at any time before the Compliance Date, the bid price for the Partnership's common units closes at $1.00 or more for a minimum of 10 consecutive business days, the Staff will provide written notification to the Partnership that it complies with the Bid Price Rule.

If the Partnership does not regain compliance with the Bid Price Rule by the Compliance Date, the Partnership may be eligible for an additional 180 calendar day compliance period. To qualify, the Partnership would need to provide written notice of its intention to cure the deficiency during the additional compliance period, which could include a reverse unit split, if necessary, provided that it meets the continued listing requirement for the market value of publicly held shares and all other initial listing standards, with the exception of the bid price requirement.

If the Partnership does not regain compliance with the Bid Price Rule by the Compliance Date and is not eligible for an additional compliance period at that time, the Staff will provide written notification to the Partnership that its common units may be delisted. At that time, the Partnership may appeal the Staff's delisting determination to a NASDAQ Listing Qualifications Panel.

Any such delisting could adversely affect the market liquidity of our units and the market price of our units could decrease. A delisting could adversely affect our ability to obtain financing for our operations or result in a loss of confidence by investors, customers, suppliers or employees.

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
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

July 31, 2019	By: */s/ Jeffrey R. Olmstead* Jeffrey R. Olmstead Chief Executive Officer
July 31, 2019	By: */s/ Philip R. Houchin* Philip R. Houchin Chief Financial Officer

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO EXCHANGE ACT RULE 13a-14(a)/15d-14(a) AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jeffrey R. Olmstead, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Mid-Con Energy Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2019

/s/ Jeffrey R. Olmstead

Jeffrey R. Olmstead
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO EXCHANGE ACT RULE 13a-14(a)/15d-14(a) AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Philip R. Houchin, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Mid-Con Energy Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2019

/s/ Philip R. Houchin

Philip R. Houchin
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying report on Form 10-Q for the period ended June 30, 2019, of Mid-Con Energy Partners, LP (the “Partnership”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Jeffrey R. Olmstead, Chief Executive Officer of Mid-Con Energy GP, LLC, the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: July 31, 2019

/s/ Jeffrey R. Olmstead
Jeffrey R. Olmstead
Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying report on Form 10-Q for the period ended June 30, 2019, of Mid-Con Energy Partners, LP (the "Partnership"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Philip R. Houchin, Chief Financial Officer of Mid-Con Energy GP, LLC, the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: July 31, 2019

/s/ Philip R. Houchin
Philip R. Houchin
Chief Financial Officer