Mid-Con Energy Partners, LP
Form 10-Q
May 02, 2016

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

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2016
OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File No.: 1-35374
Mid-Con Energy Partners, LP
(Exact name of registrant as specified in its charter)

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

2501 North Harwood Street, Suite 2410
Dallas, Texas 75201
(Address of principal executive offices and zip code)
(972) 479-5980
(Registrant's telephone number, including area code)
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x
As of May 2, 2016, the registrant had 29,785,481 limited partner units and 360,000 general partner units outstanding.

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FORWARD-LOOKING STATEMENTS

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

- business strategies;
- volatility or continued low or further declining commodity prices;
- future financial and operating results and our ability to pay distributions;
- ability to replace the reserves we produce through acquisitions and the development of our properties;
- revisions to oil and natural gas reserves estimates as a result of changes in commodity prices;
- future capital requirements and availability of financing;
- technology;
- realized oil and natural gas prices;
- production volumes;
- lease operating expenses;
- general and administrative expenses;
- cash flow and liquidity;
- availability of production equipment;
- availability of oil field labor;
- capital expenditures;
- availability and terms of capital;
- marketing of oil and natural gas;
- general economic conditions;
- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation;
- developments in oil producing and natural gas producing countries; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 1. "Financial Statements," Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Form 10-Q. In some
cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," "goal," "forecast," "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, 2015 ("Annual Report"). This document is available through our website www.midconenergypartners.com or through the Securities and Exchange Commission’s ("SEC") Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. All forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge on our website (www.midconenergypartners.com), copies of our Annual Reports, Form 10-Qs, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and the written charter of our Audit Committee are also available on our website and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

PART I
FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
Mid-Con Energy Partners, LP and subsidiaries
Condensed Consolidated Balance Sheets
(in thousands, except number of units)
(Unaudited)

	March 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$105	$ 615
Accounts receivable:		
Oil and natural gas sales	4,135	4,551
Related parties	591	—
Other	2,991	5,009
Derivative financial instruments	16,320	24,419
Prepaids and other	560	623
Total current assets	24,702	35,217
Property and Equipment:		
Oil and natural gas properties, successful efforts method:		
Proved properties	520,670	518,916
Accumulated depletion, depreciation, amortization and impairment	(238,093)	(232,008)
Total property and equipment, net	282,577	286,908
Derivative financial instruments	1,363	1,144
Other assets	3,480	3,817
Total assets	$312,122	$ 327,086
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$2,629	$ 3,185
Related parties	—	559
Accrued liabilities	69	165
Current maturities of long-term debt	19,000	30,000
Total current liabilities	21,698	33,909
Long-term debt	150,000	150,000
Asset retirement obligations	12,865	12,679
Commitments and contingencies		
EQUITY, per accompanying statements:		
Partnership equity:		
General partner interest	8	47
Limited partners- 29,785,481 and 29,724,890 units issued and outstanding as of March 31, 2016 and December 31, 2015, respectively.	127,551	130,451
Total equity	127,559	130,498

Total liabilities and equity	$312,122	$ 327,086

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 March 31,	
	2016	2015
Revenues:		
Oil sales	$11,106	$17,294
Natural gas sales	163	277
Gain on derivatives, net	2,568	1,644
Total revenues	13,837	19,215
Operating costs and expenses:		
Lease operating expenses	6,065	8,915
Oil and natural gas production taxes	592	1,109
Depreciation, depletion and amortization	6,085	7,846
Accretion of discount on asset retirement obligations	157	92
General and administrative	2,088	3,641
Total operating costs and expenses	14,987	21,603
Loss from operations	(1,150)	(2,388)
Other income (expense):		
Interest income and other	36	3
Interest expense	(2,199)	(1,727)
Total other expense	(2,163)	(1,724)
Net loss	$(3,313)	$(4,112)
Computation of net loss per limited partner unit:		
General partners’ interest in net loss	$(39)	$(50)
Limited partners’ interest in net loss	$(3,274)	$(4,062)
Net loss per limited partner unit:		
Basic	$(0.11)	$(0.14)
Diluted	$(0.11)	$(0.14)
Weighted average limited partner units outstanding:		
Limited partner units (basic)	29,768	29,487
Limited partner units (diluted)	29,768	29,487

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2016	2015
Cash Flows from Operating Activities:		
Net loss	$(3,313)	$(4,112)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	6,085	7,846
Debt issuance costs amortization	337	279
Accretion of discount on asset retirement obligations	157	92
Mark-to-market on derivatives:		
Gain on derivatives, net	(2,568)	(1,644)
Cash settlements received for matured derivatives	11,094	4,760
Cash settlements received for early terminations and modifications of derivatives, net	—	11,069
Cash premiums paid for derivatives, net	(646)	(14,348)
Non-cash equity-based compensation	390	1,944
Changes in operating assets and liabilities:		
Accounts receivable	416	1,903
Other receivables	1,586	3,574
Prepaids and other	63	82
Accounts payable and accrued liabilities	(1,497)	(3,162)
Net cash provided by operating activities	12,104	8,283
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(1,598)	(5,376)
Net cash used in investing activities	(1,598)	(5,376)
Cash Flows from Financing Activities:		
Proceeds from line of credit	—	11,000
Payments on line of credit	(11,000)	(13,000)
Offering costs	(16)	(87)
Distributions paid	—	(3,752)
Net cash used in financing activities	(11,016)	(5,839)
Net decrease in cash and cash equivalents	(510)	(2,932)
Beginning cash and cash equivalents	615	3,232
Ending cash and cash equivalents	$105	$300
Supplemental Cash Flow Information:		
Cash paid for interest	$1,936	$1,442
Non-Cash Investing and Financing Activities:		
Accrued capital expenditures - oil and natural gas properties	$844	$836

See accompanying notes to condensed consolidated financial statements

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

		Limited Partner		
	General Partner	Units	Amount	Total Equity
Balance, December 31, 2015	$ 47	29,725	$130,451	$130,498
Equity-based compensation	—	60	390	390
Offering costs	—	—	(16)	(16)
Net loss	(39)	—	(3,274)	(3,313)
Balance, March 31, 2016	$ 8	29,785	$127,551	$127,559

See accompanying notes to condensed consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements
Note 1. Organization and Nature of Operations
Nature of Operations
Mid-Con Energy Partners, LP ("we," "our," "us," the "Partnership," the "Company") is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on enhanced oil recovery ("EOR"). Our limited partner units ("common units") are traded on the National Association of Securities Dealers Automated Quotation System Global Select Market ("NASDAQ") under the symbol "MCEP". Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.
Basis of Presentation
Our unaudited condensed consolidated financial statements included herein have been prepared pursuant to the rules and regulations of the SEC. These financial statements have not been audited by our independent registered public accounting firm, except that the condensed consolidated balance sheet at December 31, 2015 is derived from the audited financial statements. Accordingly, certain information and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted in this Form 10-Q. We believe that the presentations and disclosures herein are adequate to make the information not misleading.
The unaudited condensed consolidated financial statements reflect all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the interim periods. The results of operations for the interim periods are not necessarily indicative of the results of operations to be expected for the full year. These interim financial statements should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2015.
All intercompany transactions and account balances have been eliminated.
Liquidity and Capital Resources
Our ability to finance our operations, fund our capital expenditures and acquisitions, meet or refinance our debt obligations and meet our collateral requirements will depend on our future cash flows. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, oil and natural gas prices, operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. Our primary use of cash has been for debt reduction and to fund capital spending.
Oil prices have fallen to thirteen-year lows, impacting the way we conduct business. We have implemented a number of adjustments to strengthen our financial position. In addition to increasing revenue security during 2016 and 2017 by executing additional commodity derivative contracts in November 2015 and April 2016 and restructuring our commodity derivative contracts in January 2015 to provide greater oil price protection over a longer period of time, we indefinitely suspended our quarterly cash distributions beginning with the third quarter of 2015. We are also aggressively pursuing costs reductions in order 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 lease operating expenses and general and administrative expenses.
Our liquidity position at March 31, 2016 consisted of approximately $0.1 million of available cash and $11.0 million of available borrowings under our revolving credit facility.
Our borrowing base is re-determined in or around April and October of each year. During our fall 2015 semi-annual redetermination, our borrowing base was reduced from $220.0 million to $190.0 million, consisting of a $165.0 million conforming tranche which required monthly commitment reductions of $2.5 million each month through May 2016 and a $25.0 million non-conforming tranche with a May 1, 2016 maturity. Our spring 2016 semi-annual borrowing base redetermination process is underway, with the Partnership having delivered our most recent reserve estimates and operating projections to our lenders for their review and evaluation. We anticipate this process will conclude during the second quarter 2016 and accordingly, have been granted a 30-day extension on the non-conforming tranche of our borrowing base, which now matures on June 1, 2016 and has a borrowing capacity of $15.0 million. Our liquidity position at May 2, 2016 consisted of approximately $0.4 million of available cash. Our

$165.0 million borrowing base is comprised of a $150.0 million conforming tranche and a $15.0 million non-conforming tranche.

Based on our cash balance, forecasted cash flows from operating activities and ability to monetize our hedges, if necessary, 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, given current oil prices and the discretion of our lenders to decrease our borrowing base, that the lenders under our revolving credit facility will not reduce the borrowing base to an amount below our outstanding borrowings or that our liquidity requirements will continue to be satisfied. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money 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.

Note 2. Equity Awards

We have a long-term incentive program (the "Long-Term Incentive Program") for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating, LLC ("Mid-Con Energy Operating"), who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, unrestricted units, restricted units, phantom units, distribution equivalent rights granted with phantom units and other types of awards. The Long-Term Incentive Program is administered by the members of our general partner (the "Founders") and approved by the Board of Directors of the general partner. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding.

On November 15, 2015, the Board of Directors of the general partner approved an amendment to the Long-Term Incentive Program that increased the number of common units available for issuance from 1,764,000 to 3,514,000 common units.

The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at March 31, 2016:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,183,374)
Restricted units granted, net of forfeitures	(416,280)
Equity-settled phantom units granted, net of forfeitures	(117,500)
Phantom units granted, net of forfeitures	(9,575)
Awards available for future grant	1,787,271

We recognized $0.4 million and $1.9 million of total equity-based compensation expense for the three months ended March 31, 2016 and 2015, respectively. These costs are reported as a component of general and administrative expense in our unaudited condensed consolidated statement of operations.

Unrestricted awards

During the three months ended March 31, 2016, we granted 70,000 unrestricted units with an average grant date fair value of $1.16 per unit. These units were granted to certain employees of our affiliates and certain directors and founders of our general partner. We account for unrestricted awards as equity awards since they are settled by issuing common units.

Restricted awards

We account for restricted awards as equity awards since they will be settled by issuing common units. These units vest over a two or three year period. The compensation expense we recognize associated with our restricted stock is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. We did not issue restricted units during the three months ended March 31, 2016.

A summary of our restricted units awarded for the three months ended March 31, 2016 is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2015	222,833	$ 8.49
Units granted	—	—
Units vested	(95,698)	6.96
Units forfeited	(17,577)	9.00
Outstanding at March 31, 2016	109,558	$ 8.82

As of March 31, 2016 there was approximately $0.7 million of unrecognized compensation costs related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.0 year.

Equity-settled phantom awards

We account for equity-settled phantom units as equity awards since these awards will be settled by issuing common units. These units vest over a two or three year period and do not have any rights or privileges of a common unitholder, including right to distributions, until vesting and the resulting conversion into common units. The compensation expense we recognize associated with our equity-settled phantom units is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. During the three months ended March 31, 2016, we granted 24,500 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years. These units were granted to certain employees of our affiliates and certain directors and founders of our general partner.

A summary of our equity-settled phantom units awarded for the three months ended March 31, 2016 is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2015	77,500	$ 2.81
Units granted	24,500	1.01
Units vested	(8,168)	1.16
Units forfeited	(7,500)	2.94
Outstanding at March 31, 2016	86,332	$ 2.56

As of March 31, 2016, there was approximately $0.1 million of unrecognized compensation costs related to equity-settled phantom units. The cost is expected to be recognized over a weighted average period of approximately 1.7 years.

Note 3. 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 to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and the NYMEX futures prices.

At March 31, 2016 and December 31, 2015, our net commodity derivative contracts were in a net asset position with a fair value of approximately $17.7 million and $25.6 million, respectively. All of our commodity derivative contracts are with major financial institutions that are also members of our banking group. Should one of these financial

counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss. As of March 31, 2016, all of our counterparties have performed pursuant to their commodity derivative contracts.
At March 31, 2016 and December 31, 2015, our commodity derivative contracts had maturities that extended through December 2017 and were comprised of commodity price swap, call and put contracts.
For commodity price swap contracts, at the time of execution the seller agrees to receive a fixed price at maturity in exchange for any gains or losses that might be realized from allowing the price of the underlying to float with the market until

maturity. From the perspective of the seller, these instruments limit exposure to price declines below the price fixed by the swap at the expense of participating in any price increases above the price fixed by the swap.
For commodity price call contracts, in return for a premium received at execution, the seller is obliged to pay the difference, when positive, between the market price of the underlying at maturity and the strike price. From the perspective of the seller, these instruments provide income via the premium received at the expense of any incremental gains that would have otherwise been received above the strike price.
For commodity price put contracts, in return for a premium paid, which can be effected at either execution or settlement, the purchaser has the right to receive the difference, when positive, between the strike price and the market price of the underlying at maturity. From the perspective of the purchaser, these instruments limit exposure to price declines below the strike price at the expense of premiums paid.
A collar is a combination of a put purchased or sold by a party and a call option sold or purchased by the same party.
We do not designate derivatives as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of 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 payments made or received on monthly settlements, proceeds or payments for termination of contracts prior to their expiration and premiums paid or received for new contracts. Any deferred premiums are recorded as a liability and recognized in earnings as the related contracts mature. Gains and losses on derivatives are included in cash flows from operating activities. Pursuant to the accounting standard that permits netting of assets and liabilities where the right of offset exists, we present the fair value of commodity derivative contracts on a net basis.
At March 31, 2016, we had the following oil derivatives net positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2016	$ 81.74			1,364	WTI
Puts - 2016		$ 50.00	$ —	1,964	WTI
Puts - 2017		$ 50.00	$ —	1,932	WTI

At December 31, 2015, we had the following oil derivatives net positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2016	$ 79.98			1,598	WTI
Collars - 2016		$ 50.00	$ 50.00	328	WTI
Puts - 2016		$ 50.00	$ —	1,475	WTI
Puts - 2017		$ 50.00	$ —	1,932	WTI

During the first quarter of 2015, we restructured a significant portion of our existing commodity derivative contracts that were in place at December 31, 2014 and entered into new commodity derivative contracts which extend through September 2016. In connection with the early termination of our commodity derivative contracts, we received net proceeds of approximately $11.1 million. We received approximately $5.9 million from selling calls and paid approximately $19.8 million in premiums to extend the contracts through September 2016. The restructuring also resulted in approximately $4.1 million in deferred premium put options. As of March 31, 2016, we had paid $2.6 million of the deferred put premiums in connection with contract settlements.
In connection with the November 2015 semi-annual redetermination of our borrowing base, we entered into additional commodity derivative contracts resulting in total commodity derivative contracts covering at least 80% of our 2016 projected monthly production and at least 50% of our 2017 projected monthly production, calculated based on Proved

Developed

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Producing reserves. No cash settlements were required and the contracts included deferred premiums of approximately $7.8 million that will be paid April 2016 through December 2017.

Commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our commodity derivative contracts to post collateral, it is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. We evaluate the credit standing of such counterparties by reviewing their credit rating. As of March 31, 2016, the counterparties to our commodity derivative contracts currently in place are lenders under our revolving credit facility and have investment grade ratings.

The following tables summarizes the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in our unaudited condensed consolidated balance sheets at March 31, 2016 and December 31, 2015:

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
	(in thousands)		
March 31, 2016:			
Assets			
Derivative financial instruments - current asset	$22,200	$ (5,880)	$ 16,320
Derivative financial instruments - long-term asset	5,022	(3,659)	1,363
Total	$27,222	$ (9,539)	$ 17,683
Liabilities			
Derivative financial instruments - current liability	$(212)	$ 212	$ —
Derivative deferred premium - current liability	(5,668)	5,668	—
Derivative deferred premium - long-term liability	(3,659)	3,659	—
Total	$(9,539)	$ 9,539	$ —
Net Asset	$17,683	$ —	$ 17,683

	Gross Amounts Recognized	Gross Amounts Offset in the Unaudited Condensed Consolidated Balance Sheet	Net Amounts Presented in the Unaudited Condensed Consolidated Balance Sheet
	(in thousands)		
December 31, 2015:			
Assets			
Derivative financial instruments - current asset	$29,973	$ (5,554)	$ 24,419
Derivative financial instruments - long-term asset	6,077	(4,933)	1,144
Total	$36,050	$ (10,487)	$ 25,563
Liabilities			
Derivative financial instruments - current liability	$(514)	$ 514	$ —

Derivative deferred premium - current liability	(5,040)	5,040	—
Derivative deferred premium - long-term liability	(4,933)	$ 4,933	—
Total	$(10,487)	$ 10,487	$ —
Net Asset	$25,563	$ —	$ 25,563

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

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Net settlements on matured derivatives	$11,094	$4,760
Net settlements on early terminations and modifications of derivatives	—	11,069
Change in fair value of derivatives, net	(8,526)	(14,185)
Total gain on derivatives, net	$2,568	$1,644

Note 4. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our balance sheet for cash, accounts receivable and accounts payable approximate their fair values. The carrying amount of 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. The fair value of our commodity derivative contracts is determined utilizing NYMEX-WTI closing prices for the contract period.

Fair Value Measurements

Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a three-tier fair value hierarchy that is intended to increase consistency and comparability in fair value measurements and related disclosures. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

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 and put contracts.

Level 3—Financial assets and liabilities for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. We had no transfers in or out of Levels 1, 2 or 3 at March 31, 2016 and December 31, 2015.

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. We use certain pricing models to determine the fair value of our derivative financial instruments. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources,

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analyzing pricing data in certain situations and confirming that those securities trade in active markets. See Note 3 in this section for a summary of our derivative financial instruments.

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

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 5 in this section for a summary of changes in ARO.

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: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; (iv) a market-based weighted average cost of capital rate; and (v) 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 are the product of a process that begins with Level 1 NYMEX-WTI forward curve pricing, as well as Level 3 assumptions including: pricing adjustments for estimated location and quality differentials, production costs, capital expenditures, production volumes, decline rates and estimated reserves. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimate quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. There were no impairment charges for the three months ended March 31, 2016 and 2015. For the year ended December 31, 2015, we recorded non-cash impairment charges of approximately $103.9 million.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value as of March 31, 2016 and December 31, 2015:

	Level 1	Level 2	Level 3	Fair Value
	(in thousands)			
March 31, 2016				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$—	$27,222	$—	$27,222
Derivative financial instruments - liability	—	(212)	—	(212)
Derivative deferred premiums - liability	—	—	(9,327)	(9,327)
Net derivative position	$—	$27,010	$(9,327)	$17,683
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$—	$—	$29	$29
December 31, 2015				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$—	$36,050	$—	$36,050
Derivative financial instruments - liability	—	(514)	—	(514)
Derivative deferred premiums - liability	—	—	(9,973)	(9,973)
Net derivative position	$—	$35,536	$(9,973)	$25,563
Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis				
Asset retirement obligations	$—	$—	$4,924	$4,924
Impairment of proved oil and natural gas properties	$—	$—	$103,938	$103,938

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

	Three Months Ended March 31, 2016	Year Ended December 31, 2015
	(in thousands)	
Balance of Level 3 at beginning of period	$(9,973)	$—
Derivative deferred premiums - purchases	—	(11,914)
Derivative deferred premiums - settlements	646	1,941
Balance of Level 3 at end of period	$(9,327)	$(9,973)

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 not changes in valuation techniques or related inputs for the three months ended March 31, 2016 and for the year ended December 31, 2015.

Note 5. 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 production operations. These asset retirement obligations are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well and determine our ARO by calculating the present value of estimated cash flow related to the estimated future liability. Determining the future restoration and removal 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 estimate the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. 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 asset retirement obligations 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. Over time, the liability is accreted each period toward its future value and is recorded in our 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.

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

	Three Months Ended March 31, 2016	Year Ended December 31, 2015
	(in thousands)	
Asset retirement obligations - beginning of period	$12,679	$7,363
Liabilities incurred for new wells and interest	29	42
Liabilities settled upon plugging and abandoning wells	—	(40)
Revision of estimates [1]	—	4,882
Accretion expense	157	432
Asset retirement obligations - end of period	$12,865	$12,679

(1) The revision of estimates that occurred during the year ended December 31, 2015 is primarily due to a change in estimated plugging and abandonment costs based on 2015 settlements.

As of March 31, 2016 and December 31, 2015, all of our ARO were classified as long-term and were reported as "Asset Retirement Obligations" in our unaudited condensed consolidated balance sheets.

Note 6. Debt

A summary of our debt at March 31, 2016 and December 31, 2015 is presented below:

	March 31, 2016	December 31, 2015
	(in thousands)	
Revolving credit facility	$169,000	$180,000
Less: current portion	19,000	30,000
Total long-term debt	$150,000	$150,000

At March 31, 2016, we had $169.0 million of borrowings outstanding under our revolving credit facility. Borrowings under the revolving credit facility did not exceed the borrowing base of $180.0 million at March 31, 2016. Borrowings under the facility are secured by liens on not less than 90% of our assets and the assets of our subsidiaries. Our debt consists of $19.0 million classified as current and $150.0 million classified as long-term. At March 31, 2016, maturities of our debt were $19.0 million in 2016 and $150.0 million in 2018.

The borrowing base of our revolving credit facility is collectively determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations in or around April and October of each year with an additional redetermination, either at our request or at the request of the lender, during the period between each scheduled borrowing base determination. 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. We initiated our semi-annual borrowing base redetermination in April 2016 and expect to finalize this process during the second quarter of 2016. We do expect that our borrowing base will be reduced as a result of continued declines in oil and natural gas prices, however, the precise amount of the reduction is not known at this time. We remain focused on improving our capital structure, providing structural liquidity and minimizing capital expenditures, as evidenced by our 2016 capital program. As of May 2, 2016, debt has been reduced by $4.0 million from the March 31, 2016 balance and the outstanding balance at this date was $165.0 million.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of the Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50% and the one month adjusted London Interbank Offered Rate ("LIBOR") plus 1.0%, all of which are subject to a margin that varies from 1.00% to 2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 2.00% to 3.75% per annum according to the borrowing base usage. For the three months ended March 31, 2016, the average effective rate was approximately 4.17%. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

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

During the semi-annual redetermination in April 2015, the borrowing base under the revolving credit facility was reduced to $220.0 million from $240.0 million. No other material terms of the original credit agreement were amended.

During November 2015, the semi-annual redetermination of our borrowing base and amendment of the underlying revolving credit facility was completed. This redetermination resulted in a borrowing base of $190.0 million, consisting of a $165.0 million conforming tranche which required six monthly commitment reductions of $2.5 million each through May 2016 and a $25.0 million non-conforming tranche that matured on May 1, 2016. The credit facility amendment also designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. This redetermination also required that by December 10, 2015, we enter into commodity derivative contracts of not less than 80% of our 2016 projected monthly production and not less than 50% of our 2017 projected monthly production, calculated based on Proved Developed Producing reserves. These requirements were satisfied during November 2015 with the execution of additional commodity derivative contracts maturing in 2016 and 2017. In connection with this amendment to our revolving credit facility, we incurred financing fees and expenses of approximately $0.7 million, which will be amortized over the remaining life of the revolving credit facility. Such amortized expenses are recorded in "interest expense" on our unaudited condensed consolidated statements of operations.

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, restrictions on certain transactions and payments, including distributions. If we fail to perform our obligations under these and other covenants, the revolving credit commitments may be terminated and any outstanding indebtedness under the credit agreement, together with accrued interest could be declared immediately due and payable. We were in compliance with these covenants as of and during the three months ended March 31, 2016.

Note 7. Commitments and Contingencies

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

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

Our general partner has entered into employment agreements with the following named employees of our general partner: Jeffrey R. Olmstead, President and Chief Executive Officer and Charles R. Olmstead, Executive Chairman of the Board of our general partner. The employment agreements provide for a term that commenced on August 1, 2011 and automatically renewed on August 1, 2014 for an additional year, unless earlier terminated, and would continue to automatically renew for one-year terms unless either we or the employee gives written notice of termination at least by February 1st preceding any such August 1st. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities and authority as the board of directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him. The agreement stipulates that if there is a change of control, termination of employment, with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $0.3 million to $0.7 million, including the value of vesting of any outstanding units.

Note 8. Equity

Common Units

At March 31, 2016 and December 31, 2015, the Partnership's equity consisted of 29,785,481 and 29,724,890 common units, respectively, representing approximately a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement (the "Agreement") to sell, from time to time through or to the Managers (as defined in the Agreement), up to $50.0 million in common units representing limited partner interests. The sales, if any, of common units made under the Agreement will be made by any method permitted by law deemed to be an "at-the-market-offering" as defined in Rule 415 under the Securities Act of 1933, as amended (the "Securities Act"), including without limitation, sales made directly on the NASDAQ, on any other existing trading market for our common units or to or through a market maker. From the period of the original agreement to March 31, 2016, we did not sell any common units.

Cash Distributions

Our partnership agreement requires us to distribute all of our available cash on a quarterly basis. Our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs, including cash from working capital borrowings. There is no assurance as to the future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Prolonged declines in commodity prices prompted us to suspend cash distributions beginning with the third quarter of 2015 in an effort to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. Quarterly distributions continue to be indefinitely suspended at March 31, 2016. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions.

Allocation of Net Income

Net income is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership during the period.

Note 9. 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.

Reimbursement of Expenses

We are party to a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides certain services to us, including management, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. During the three months ended March 31, 2016 and 2015, we reimbursed Mid-Con Energy Operating approximately $0.8 million and $0.9 million for direct expenses. These costs are included in the general and administrative expenses in our unaudited condensed consolidated statements of operations.

Other Transactions with Related Persons

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies or COPAS overhead fee). We and those third parties pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. For the three months ended March 31, 2016 and 2015, we paid Mid-Con Energy Operating $1.7 million and $2.1 million, respectively, for COPAS overhead fees, pumper and supervision fees pursuant to the operating agreements. For the three months ended March 31, 2016 and 2015, Mid-Con Energy Operating billed us $0.7 million and $1.0 million, respectively, for oilfield services performed by our affiliate ME3 Oilfield Service. These services were billed according to operating agreements.

At March 31, 2016, we had a net receivable from Mid-Con Energy Operating of approximately $0.6 million which was comprised of a joint interest billing receivable of approximately $0.9 million and a payable for operating services of approximately $0.3 million. These amounts are included in the Accounts receivable-related parties in our unaudited condensed consolidated balance sheets.

Note 10. New Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued a comprehensive new revenue recognition standard that supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring those goods or services. The new standard also requires significantly expanded disclosure regarding the qualitative and quantitative information of an entity's nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The standard creates a five-step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's

application impact to individual financial statement line items. This standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.
In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The amendments in ASU 2014-15 are intended to define management's responsibility to evaluate whether there is a substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosures. This standard is effective for the annual periods ending after December 15, 2016, and for interim periods within annual period beginning after December 15, 2016. Early adoption is permitted. As of March 31, 2016 the Partnership has not elected early adoption.
In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting. The guidance simplifies the accounting for employee stock-based payment transactions including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification of awards as either equity or liabilities, and classification of related amounts within the statement of cash flows. The guidance requires the recognition of the income tax effects of awards in the income statement when the awards vest or are settled, thus eliminating additional paid in capital pools. The guidance also allows for the employer to repurchase more of an employee’s shares for tax withholding purposes without triggering liability accounting. In addition, the guidance allows for a policy election to account for forfeitures as they occur rather than on an estimated basis. The guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period and early adoption is permitted. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements upon adoption of this standard.

Note 11. Subsequent Events

On April 11, 2016, we entered into new oil derivative contracts covering a total 240,000 barrels of future production which extend from January 2017 through December 2017.
On April 1, 2016, Mr. Charles L. McLawhorn III was named Vice President, General Counsel and Secretary of the General Partner, replacing Mr. Nathan P. Pekar whose resignation was effective on January 8, 2016.
As of May 2, 2016, debt has been reduced by $4.0 million from the March 31, 2016 balance and the outstanding balance at this date was $165.0 million.
Our spring 2016 borrowing base redetermination process is underway, with the Partnership having delivered our most recent reserve estimates and operating projections to our lenders in for their review and evaluation. We anticipate this process will conclude during the second quarter 2016 and accordingly, have been granted a 30-day extension of our borrowing base, which now matures on June 1, 2016. During this extension, our borrowing base is $165.0 million, comprised of a $150.0 million conforming tranche and a $15.0 million non-conforming tranche.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management’s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our unaudited condensed consolidated financial statements and the related notes thereto, as well as our Annual Report.

Overview

Mid-Con Energy Partners, LP ("we," "our," "us," the "Partnership," the "Company") is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on EOR. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our common units are traded on the NASDAQ under the symbol "MCEP".
Our properties are located primarily in the Mid-Continent and Permian Basin regions of the United States in five core areas: Southern Oklahoma, Northeastern Oklahoma, parts of Oklahoma, Colorado and Texas within the Hugoton, Texas Gulf Coast and Texas within the Eastern Shelf of the Permian ("Permian"). Our properties primarily consist of

mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Recent Developments
Operating Performance
Low oil and natural gas prices continue to constrain the Partnership's operating income by negatively impacting top-line revenues and corresponding operating margins. As detailed below, the Partnership has responded to this operating environment with numerous cost control initiatives and ongoing portfolio evaluations. During the first quarter 2016, production declined approximately 10% sequentially. Relative to the fourth quarter 2015 and on a per Boe basis, we reduced lease operating expenses approximately 18% while general and administrative costs increased by approximately 17% largely reflecting year-end audit and K-1 tax preparation fees that historically occur during the first quarter. Sequential cash operating expenses declined approximately 6% quarter-over-quarter to average $26.39/Boe. From operating cash flows we repaid $11.0 million in debt during the quarter and funded approximately $1.7 million in capital spending.

Development of our large waterflood projects continued in the first quarter of 2016, notably in our Cleveland Field Unit (Northeastern Oklahoma) and Corsica Bend Conglomerate Unit (Permian). The Cleveland Field Unit (Pawnee, Oklahoma) has demonstrated strong waterflood response from recent injection. Additional capital is planned for the remainder of 2016 to further expand the waterflood development at the Cleveland Field Unit. An additional injection well and water supply well were made operational in an under-developed portion of the Corsica Bend Conglomerate Unit (Stonewall County, Texas) characterized by high oil cuts. Initial waterflood response from this development is expected this year. After initial waterflood response is observed, additional development capital is planned in 2016.

In the first quarter of 2016, we drilled and completed two wells in the Permian core area and both are currently in a test phase. We plan to drill two new wells in the Permian area after testing of the recent new drills is conclusive. A recompletion in the Permian core area in the first quarter of 2016 was successful and the concept will be expanded with three additional recompletions planned for the second quarter of 2016.
Low Price Environment Initiatives
In response to the significant declines in benchmark oil prices that unfolded between November 2014 and February 2016, we remain focused on further driving costs down. Our ongoing cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of lease operating expenses and general and administrative expenses. Wells that were not economically viable, at then prevailing prices, were shut-in provided there were no contractual, operating or reservoir constraints precluding the suspension of operations. Based on this assessment, we elected to shut-in approximately 184 uneconomic wells, the majority of which were shut-in late January 2016. We will continue to monitor pricing and expenses to determine when to return these wells to production.
Commodity Prices
Our revenues and net income are sensitive to oil and natural gas prices which have been and are expected to continue to be highly volatile. In the first quarter of 2016, the front-month NYMEX-WTI futures price averaged approximately $34 per barrel, compared to approximately $49 per barrel in the first quarter of 2015. During the three months ended March 31, 2016, the front-month NYMEX-WTI futures price ranged from a low of approximately $26 per barrel to a high of approximately $41 per barrel.
Distributions
As of May 2, 2016, cash distributions continue to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate distributions and also prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders.
Financing Activities

Our spring 2016 borrowing base redetermination process is underway, with the Partnership having delivered our most recent reserve estimates and operating projections to our lenders for their review and evaluation. We anticipate this process will conclude during the second quarter of 2016 and accordingly, have been granted a 30-day extension on the non-conforming tranche of our borrowing base, which now matures on June 1, 2016 and has a borrowing capacity of $15.0 million.

Equity Awards

On January 21, 2016, the Board of Directors of our general partner authorized the issuance of 70,000 unrestricted common units and 24,500 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years. The equity-settled phantom units do not have any rights or privileges of a unitholder, including right to distributions, until vesting and the resulting conversion into common units. These units were granted to certain employees of our affiliates and certain directors and founders of our general partner.

Departure of Certain Officers

On January 8, 2016, Nathan P. Pekar resigned from his position as General Counsel, Secretary and Vice President. Mr. Pekar served as a third party consultant after his resignation until March 31, 2016.

Business Environment

The markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future, which means that the price of oil may fluctuate widely. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil reserves that we can economically produce and our access to capital. In late 2014, prices for oil, natural gas and NGLs began to decline, and prices continued to decline throughout 2015 and into 2016. For perspective, prices for front month NYMEX-WTI crude oil futures traded within a range of $26.21 and $41.45 per barrel in the first quarter of 2016, ending the quarter at $38.34 per barrel while front month NYMEX Henry Hub natural gas futures traded within a range of $1.64 to $2.47 per MMBtu over the same period, ending the quarter at $1.96 per MMBtu. The continued decline in commodity prices has had an impact on our unit price. During the three months ended March 31, 2016, our common unit price fluctuated between a closing high of $1.83 to a closing low of $0.78.

The objective of our risk management program is to achieve more predictable cash flows by reducing our exposure to short-term fluctuations in the price of oil and natural gas. We believe this strategy will serve to secure a baseline portion of our revenues and, by retaining some opportunity to participate in upward price movements, may also enable us to realize higher revenues during periods when prices rise. To this end, we utilize commodity derivatives, namely swap, call and put contracts, to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts and/or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. We conduct our risk management activities exclusively with participant lenders in our revolving credit facility. In January 2015, we restructured a significant portion of our hedge portfolio to limit downside and volatility due to the then prevailing commodity price environment and in November 2015 and April 2016, we entered into additional oil commodity contracts covering a portion of our anticipated oil production in 2016 and 2017.

Our business faces the challenge of natural production declines. As initial reservoir pressures are depleted, oil production from a given well or formation decreases. Although our waterflood operations tend to restore reservoir pressure and production, once a waterflood is fully effected, production, once again, begins to decline. Our future growth will depend on our ability to continue to add reserves in excess of our production. Our focus on adding reserves is primarily through improving the economics of producing oil from our existing fields and, secondarily, through acquisitions of additional proved reserves. Our ability to add reserves through exploitation projects and acquisitions is dependent upon many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and close acquisitions.

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

How We Evaluate Our Operations

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which will provide stability and, over time, growth of distributions to our unitholders. The amount of cash that we can distribute to our unitholders depends principally on the cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other factors:

- the amount of oil and natural gas we produce;
- the prices at which we sell our oil and natural gas production;

- our ability to hedge commodity prices; and

- the level of our operating and administrative costs.

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;
- Lease operating expenses; and
- Adjusted EBITDA.

Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess:

- the cash flow generated by our assets, without regard to financing methods, capital structure or historical cost basis; and
- our ability to incur and service debt and fund capital expenditures.

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

Results of Operations

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

	Three Months Ended March 31,	
	2016	2015
Revenues:		
Oil sales	$11,106	$17,294
Natural gas sales	163	277
Gain on derivatives, net	2,568	1,644
Total revenues	$13,837	$19,215
Operating costs and expenses:		
Lease operating expenses	$6,065	$8,915
Oil and natural gas production taxes	$592	$1,109
Depreciation, depletion and amortization	$6,085	$7,846
General and administrative (1)	$2,088	$3,641
Interest expense	$2,199	$1,727
Production:		
Oil (MBbls)	369	391
Natural gas (MMcf)	130	127
Total (MBoe)	390	412
Average net production (Boe/d)	4,286	4,578
Average sales price:		
Oil (per Bbl):		
Sales price	$30.10	$44.23
Effect of net settlements on matured derivative instruments (2)	$18.86	$11.45
Realized oil price after derivatives	$48.96	$55.68
Natural gas (per Mcf):		
Sales price (3)	$1.25	$2.18
Average unit costs per Boe:		
Lease operating expenses	$15.55	$21.64
Oil and natural gas production taxes	$1.52	$2.69
Depreciation, depletion and amortization	$15.60	$19.04
General and administrative expenses	$5.35	$8.84

(1) General and administrative expenses include non-cash equity-based compensation of $0.4 million and $1.9 million for the three months ended March 31, 2016 and 2015.

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

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

Three Months Ended March 31, 2016 Compared with the Three Months Ended March 31, 2015
We reported net loss of approximately $3.3 million for the three months ended March 31, 2016 compared to net loss of approximately $4.1 million for the three months ended March 31, 2015. The $0.8 million change was attributable to lower lease operating expenses ("LOE"), lower depreciation, depletion and amortization expense ("DD&A") and lower general and administrative expenses ("G&A"), partially offset by lower oil and natural gas sales prices and volumes in 2016.
Sales Revenues. Revenues from oil and natural gas sales for the three months ended March 31, 2016 were approximately $11.3 million as compared to approximately $17.6 million for the three months ended March 31, 2015. In 2016, the revenue decrease was primarily due to lower oil and natural gas prices driven by market conditions. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the three months ended March 31, 2016 was approximately $30.10 compared to approximately $44.23 for the three months ended March 31, 2015. Commodity prices continue to be volatile. In the first quarter of 2016, the front-month NYMEX-WTI futures price averaged approximately $34 per barrel, compared to approximately $49 per barrel in the first quarter of 2015. During the three months ended March 31, 2016, the front-month NYMEX-WTI futures price ranged from a low of approximately $26 per barrel to a high of approximately $41 per barrel.
On average, our production volumes for the three months ended March 31, 2016 were approximately 390 MBoe, or approximately 4,286 Boe per day. In comparison, our total production volumes for the three months ended March 31, 2015 were approximately 412 MBoe, or approximately 4,578 Boe per day. The decrease in production volumes was primarily due to the shut-in of uneconomic wells.
Effects of Commodity Derivative Contracts. We utilize NYMEX-WTI derivative contracts to hedge against changes in commodity prices. To the extent the future commodity price outlook declines between measurement periods, we will have gains on our derivative contracts, net of deferred premiums. To the extent future commodity price outlook increases between measurement periods, we will have losses on our derivative contracts, including deferred premiums. During the three months ended March 31, 2016, we recorded a net gain of approximately $2.6 million which was composed of approximately $11.1 million gain on net cash settlements of derivative contracts and approximately $8.5 million non-cash loss on changes in fair value of derivative contracts. For the three months ended March 31, 2015, we recorded a net gain from our commodity derivative contracts of approximately $1.6 million, which was composed of approximately $15.8 million gain on net cash settlements of derivative contracts and approximately $14.2 million non-cash loss on changes in fair value of derivative contracts. The gain on net cash settlements of approximately $15.8 million consisted of approximately $11.1 million for the early termination of contracts in place and approximately $4.7 million from settled derivatives in place during the three months ended March 31, 2015. The non-cash loss on changes in fair value of derivative contracts of approximately $14.2 million was primarily related to the $11.1 million gain from early termination of the contracts and to the $3.1 million gain upon settlement in January 2015 for contracts that were not early terminated or modified, both of which were previously recognized in the results of operations during the year ended December 31, 2014.
Lease Operating Expenses. For the three months ended March 31, 2016, our LOE were approximately $6.1 million, or $15.55 per Boe, compared to approximately $8.9 million, or approximately $21.64 per Boe, for the three months ended March 31, 2015. The decrease in total LOE and average costs per Boe for the three months ended March 31, 2016 reflect the operational decisions to shut-in 184 uneconomic wells during December 2015 and January 2016.
Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues and exclude the effects of our commodity derivative contracts. Our production taxes for the year three months ended March 31, 2016 were approximately $0.6 million, or approximately $1.52 per Boe, for an effective tax rate of approximately 5.3%, compared to approximately $1.1 million, or approximately $2.69 per Boe, for an effective tax rate of approximately 6.3% for the three months ended March 31, 2015. The decrease in production taxes for the three months ended March 31, 2016 was attributable to lower oil and natural gas revenues driven by lower prices and to the approval by the Oklahoma Tax Commission of an EOR Production Tax Exemption for one of our Northeastern Oklahoma units. The EOR exemption will extend through March 2018. The decrease in production tax per Boe was primarily attributable to a greater proportion of Permian production, which bears a lower state production tax rate, and the EOR tax exemption in Northeastern Oklahoma.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the three months ended March 31, 2016 were approximately $6.1 million, or approximately $15.60 per Boe, compared to approximately $7.8 million, or approximately $19.04 per Boe, for the three months ended March 31, 2015. The decrease in DD&A expense and DD&A per Boe is primarily due to the asset impairment recorded in the fourth quarter of 2015 which reduced the carrying value of our oil and natural gas properties and to the reductions in development costs during the three months ended March 31, 2016.

General and Administrative Expenses. G&A expenses were approximately $2.1 million, or approximately $5.35 per Boe, for the three months ended March 31, 2016, compared to approximately $3.6 million, or approximately $8.84 per Boe, for the three months ended March 31, 2015. The decrease in G&A was primarily due to decreases in equity-based compensation costs resulting from lower price of our common units and fewer units issued in 2016. G&A expenses included non-cash equity-based compensation of approximately $0.4 million and approximately $1.9 million for the three months ended March 31, 2016 and 2015, respectively.

Interest Expense. Our interest expense for the three months ended March 31, 2016 was approximately $2.2 million, compared to approximately $1.7 million for the three months ended March 31, 2015. The increase in interest expense during the three months ended March 31, 2016 reflects a higher effective interest rate as a result of the higher pricing grid established during the fall 2015 borrowing base redetermination.

Liquidity and Capital Resources

Our ability to finance our operations, fund our capital expenditures and acquisitions, meet or refinance our debt obligations and to meet our collateral requirements will depend on our future cash flows. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, oil and natural gas prices, operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors. Our primary use of cash has been for debt reduction and to fund capital spending.

Oil prices have fallen to thirteen-year lows, impacting the way we conduct business. We have implemented a number of adjustments for the upcoming year to strengthen our financial position. In addition to increasing revenue security during 2016 and 2017 by executing additional commodity derivative contracts in November 2015 and April 2016 and restructuring our commodity derivative contracts in January 2015 to provide greater oil price protection over a longer period of time, we indefinitely suspended our quarterly cash distributions beginning with the third quarter of 2015. We are also aggressively pursuing costs reductions in order 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 lease operating expenses and general and administrative expenses.

Our liquidity position at March 31, 2016 consisted of approximately $0.1 million of available cash and $11.0 million of available borrowings under our revolving credit facility. Our borrowing base is re-determined in or around April and October of each year. During our fall 2015 redetermination, our borrowing base was reduced from $220.0 million to $190.0 million, consisting of a $165.0 million conforming tranche which required monthly commitment reductions of $2.5 million each month through May 2016 and a $25.0 million non-conforming tranche with a May 1, 2016 maturity.

Our spring 2016 borrowing base redetermination process is underway, with the Partnership having delivered our most recent reserve estimates and operating projections to our lenders for their review and evaluation. We anticipate this process will conclude during the second quarter 2016 and accordingly, have been granted a 30-day extension of our borrowing base, which now matures on June 1, 2016. During this extension, our borrowing base is $165.0 million, comprised of a $150.0 million conforming tranche and a $15.0 million non-conforming tranche. Our liquidity position at May 2, 2016 consisted of approximately $0.4 million of available cash.

Based on our cash balance, forecasted cash flows from operating activities and ability to monetize our hedges, if necessary, 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, given current oil prices and the discretion of our lenders to decrease our borrowing base, that the lenders under our revolving credit facility will not reduce the borrowing base to an amount below our outstanding borrowings or that our liquidity requirements will continue to be satisfied. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable. The cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide any new funding.

Cash Flows

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

Three Months
Ended
March 31,

	2016	2015
Operating activities	$12,104	$8,283
Investing activities	$(1,598)	$(5,376)
Financing activities	$(11,016)	$(5,839)

Operating Activities. Net cash provided by operating activities was approximately $12.1 million and $8.3 million for the three months ended March 31, 2016 and 2015, respectively. The $3.8 million increase from 2015 to 2016 was primarily attributable to the positive net impact of our hedging activities and lower LOE due to the shut-in of uneconomic wells, offset by lower oil sales revenues resulting from lower oil prices and lower volumes sold in 2016.
Investing Activities. Net cash used in investing activities was approximately $1.6 million and approximately $5.4 million for the three months ended March 31, 2016 and 2015, respectively. Cash used in investing activities during the three months ended March 31, 2016 included approximately $1.6 million on capital expenditures for drilling and completion activities in our Gulf Coast, Northeastern Oklahoma and Hugoton core areas. Cash used in investing activities during the three months ended March 31, 2015 included capital expenditures of approximately $5.4 million primarily for drilling and completion activities in our Northeastern Oklahoma and Permian properties.
Financing Activities. Net cash used in financing activities was approximately $11.0 million and $5.8 million for the three months ended March 31, 2016 and 2015, respectively. Cash used in financing activities during the three months ended March 31, 2016 included payments on our revolving credit facility of approximately $11.0 million. Net cash used in financing activities during the three months ended March 31, 2015 included net payments on our revolving credit facility of $2.0 million, cash distributions to unitholders of approximately $3.7 million and approximately $0.1 million of incremental offering costs.

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. Given the current commodity pricing situation, we have limited capital spending to include only the most economically viable development projects. 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.

We currently expect capital spending for the remainder of 2016 for the development, growth and maintenance of our oil and natural gas properties to be approximately $7.3 million. We will consider adjustments to this capital program based on surplus operating cash flows in concert with our evaluation of additional development opportunities that are identified during the year.

Revolving Credit Facility

We have a $250.0 million senior-secured revolving credit facility that expires in November 2018. At March 31, 2016, our borrowing base was $180.0 million, consisting of a $155.0 million conforming tranche and a $25.0 million non-conforming tranche with a May 1, 2016 maturity. At March 31, 2016, we had $169.0 million of borrowings outstanding under our revolving credit facility.

The borrowing base is determined by the lenders participating in our credit facility based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary. The borrowing base is subject to scheduled redeterminations in or around April and October of each year with an additional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a commodity derivative contract.

Our spring 2016 borrowing base redetermination process is underway, with the Partnership having delivered our most recent reserve estimates and operating projections to our lenders for their review and evaluation. We anticipate this process will conclude during the second quarter of 2016 and accordingly, have been granted a 30-day extension on the non-conforming tranche of our borrowing base, which now matures on June 1, 2016 and has a borrowing capacity of $15.0 million.

During November 2015, the semi-annual redetermination of our borrowing base and amendment of the underlying revolving credit facility was completed. This redetermination resulted in a borrowing base of $190.0 million, consisting of a $165.0 million conforming tranche which required six monthly commitment reductions of $2.5 million each through May 2016 and a $25.0 million non-conforming tranche. The credit facility amendment designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. This redetermination also required that by December 10, 2015 we enter into commodity derivative contracts of not less than 80% of our 2016 projected monthly production and not less than 50% of our 2017 projected monthly production, calculated based on Proved Developed Producing reserves. These requirements were satisfied during November 2015 with the execution of additional commodity derivative contracts maturing in 2016 and 2017. Borrowings under our amended credit facility are secured by liens on not less than 90% of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders.

During April 2015, our borrowing base under the revolving credit facility was decreased from $240.0 million to $220.0 million. No other material terms of the original credit agreement were amended.

The facility requires us and our subsidiaries to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0 and a Current Ratio of not less than 1.0 to 1.0. We were in compliance with these covenants as of and during the three months ended March 31, 2016.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of 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 1.0% to 2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the conforming borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 2.0% to 3.75% per annum according to the borrowing base usage. For the three months ended March 31, 2016, the average effective interest rate was approximately 4.17%. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

See Note 6 to the Unaudited Condensed Consolidated Financial Statements for additional information about our revolving credit facility.

Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity prices and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and NYMEX-WTI futures prices. As of March 31, 2016, we have commodity derivative contracts covering approximately 79% of the remainder 2016 average daily production and approximately 46% of our 2017 average daily production (calculated based on the mid-point of our production guidance released on May 2, 2016).

At March 31, 2016, our open commodity derivative contracts were in a net asset position with a fair value of approximately $17.7 million. All of our commodity derivative contracts are with major financial institutions that are also members of our banking group. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss. As of March 31, 2016, all of our counterparties have performed pursuant to the obligations specified in their commodity derivative contracts.

At March 31, 2016, our derivative contracts had maturities in 2016 and 2017 and were comprised of commodity price swap, call and put contracts. For commodity price swap contracts, at the time of execution, the seller agrees to receive a fixed price at maturity in exchange for any gains or losses that might be realized from allowing the price of the underlying to float with the market until maturity. From the perspective of the seller, these instruments limit exposure to price declines below the price fixed by the swap at the expense of participating in any price increases above the price fixed by the swap.

For commodity price call contracts, in return for a premium received, which can be effected at either execution or settlement, the seller is obliged to pay the difference, when positive, between the market price of the underlying at maturity and the strike price. From the perspective of the seller, these instruments provide income via the premium received at the expense of any incremental gains that would have otherwise been received above the strike price.

For commodity price put contracts, in return for a premium paid, which can be effected at either execution or settlement, the purchaser has the right to receive the difference, when positive, between the strike price and the market price of the underlying at maturity. From the perspective of the purchaser, these instruments limit exposure to price declines below the strike price at the expense of premiums paid.

We do not designate derivatives as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of 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 payments made or received on monthly settlements, proceeds 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.

See Note 3 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our derivative contracts.

Off–Balance Sheet Arrangements

As of March 31, 2016, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements

See Note 10 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding recently issued accounting pronouncements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a variety of market risks including commodity price risk, interest rate risk and credit risk. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

Our primary market risk exposure is the pricing we receive for our oil and natural gas sales. Historically, energy prices have exhibited, and are generally expected to continue to exhibit, some of the highest volatility levels observed within the commodity and financial markets. The prices we receive for our oil and natural gas sales depend on many factors outside of our control, such as the strength of the global economy and changes in supply and demand.

Our risk management program is intended to reduce exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivatives, namely swap, call and put contracts, to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts and/or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders.

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require the counterparties to our derivative contracts to post collateral, it is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. We evaluate the credit standing of such counterparties by reviewing their credit ratings. The counterparties to our derivative contracts currently in place are lenders under our revolving credit facility and have investment grade ratings. We expect to enter into future derivative contracts with these or other lenders under our revolving credit facility whom we expect will also carry investment grade ratings.

Our commodity price risk management activities are recorded at fair value and thus changes to the future commodity prices could have the effect of reducing net income and the value of our securities. The fair value of our oil commodity contracts at March 31, 2016 was a net asset of approximately $17.7 million. A 10% change in oil prices, with all other factors held constant, would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity derivative contracts of approximately $4.9 million. See Note 3 to the Unaudited Condensed Consolidated Financial Statements for additional information.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to debt obligations. At March 31, 2016, we had debt outstanding of $169.0 million, with an effective interest rate of 4.17%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate would be approximately $0.7 million on an annual basis. At March 31, 2016, our revolving credit facility allowed for borrowings up to $180.0 million at an interest rate ranging from LIBOR plus a margin ranging from 2.0% to 3.75% or the prime rate plus a margin ranging from 1.0% to 2.75%, depending on the amount borrowed. The prime rate will be the United States prime rate as announced from time-to-time by Wells Fargo Bank, National Association. See Note 6 to the Unaudited Condensed Consolidated Financial Statements for additional information.

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Counterparty and Customer Credit Risk

We are subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current 2016 production. The inability or failure of any of our customers to meet its obligations to us or its insolvency or liquidation may adversely affect our financial results. We monitor our exposure to these counterparties primarily by reviewing credit ratings and payment history. As of March 31, 2016, our current purchasers had positive payment histories.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our chief executive officer (principal executive officer) and chief financial officer (principal financial officer), the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of March 31, 2016. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we filed under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Form 10-Q.

Changes in Internal Controls Over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the quarterly period ended March 31, 2016, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In the course of our ongoing preparations for making management’s report on internal control over financial reporting as required by Section 404 of the Sarbanes-Oxley Act of 2002, from time to time we have identified areas in need of improvement and have taken remedial actions to strengthen the affected controls as appropriate. We make these and other changes to enhance the effectiveness of our internal control over financial reporting, which do not have a material effect on our overall internal control over financial reporting.

PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

There have been no material changes with respect to the risk factors disclosed in our Annual Report for the year ended December 31, 2015.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

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

Exhibit No.	Exhibit Description
10.1	Amendment No.6 to Credit Agreement, dated as of February 12, 2015, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.01 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on February 17, 2015).
10.2	Amendment No.7 to Credit Agreement, dated as of November 30, 2015, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 1, 2015).
10.3+	Amendment No.8 to Credit Agreement, dated as of April 29, 2016, among Mid-Con Energy Properties, LLC, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent and Collateral Agent and the lenders party thereto.
10.4	Amendment No. 1 to Mid-Con Energy Partners, LP Long-Term Incentive Program (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the Commission on November 20, 2015).
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

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+Filed herewith

++In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this Form 10-Q shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange

Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed."

SIGNATURE

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

	MID-CON ENERGY PARTNERS, LP	
	By:	Mid-Con Energy GP, LLC, its general partner
May 2, 2016	By:	/s/ Michael D. Peterson Michael D. Peterson Chief Financial Officer