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MID-CON ENERGY PARTNERS, LP

FORM 10-K
(Annual Report)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10–K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 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 No.)

2431 East 61st Street, Suite 850
Tulsa, Oklahoma 74136
(Address of principal executive offices and zip code)

(918) 743-7575
(Registrant's telephone number, including area code)

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

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well–known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S–K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III or any amendment to the Form 10–K. ☒

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 definition 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	☐
Non-accelerated filer	☒	Smaller reporting company	☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b–2 of the Exchange Act). YES ☐ NO ☒

The aggregate market value of the common units held by non-affiliates of the registrant was approximately $45.7 million on June 30, 2016, based on $1.93 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

Documents incorporated by Reference: None.

As of February 28, 2017 , the registrant had 30,000,127 common units and 360,000 general partner units outstanding.

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GLOSSARY

The following is a list of certain acronyms and terms generally used in the industry and throughout this document. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been excerpted from the applicable definitions contained in Rule 4-10(a) of Regulation S-X.

ARO: Asset retirement obligations

Basin: A large depression on the earth's surface in which sediments accumulate.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/d : One Bbl per day

Behind Pipe: Reserves associated with recompletion projects which have not been previously produced.

Boe: Barrel of Oil Equivalent, equals six Mcf of natural gas or one Bbl of oil based on a rough energy equivalency. This is a physical correlation of heat content and does not reflect a value or price relationship between the commodities.

Boe/d: One Boe per day

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Conventional Hydraulic Fracturing: Hydraulic fracturing is used to stimulate production from new and existing oil and natural gas wells. Large volumes of fracturing fluids, or "fracing fluids," are pumped deep into the well at high pressures sufficient to cause the reservoir rock to break or fracture. Almost all frac fluid mixtures are comprised of more than 95 percent water. As the pressure builds within the well, rock beds begin to crack. More fluid is added while the pressure is increased until the rock beds finally fracture, creating channels for trapped oil and natural gas to flow into the well and up to the surface. The fractures are kept open with proppants made of small granular solids (generally sand) to ensure the continued flow of fluids. By creating or even restoring fractures, the surface area of a formation exposed to the borehole increases and the fracture provides a conductive path that connects the reservoir to the well. These new paths increase the rate that fluids can be produced from the reservoir formations, in some cases by many hundreds of percent.

Developed Acreage: Acres spaced or assigned to productive wells or wells capable of production.

Development Well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

EOR: Enhanced Oil Recovery

EPA: United States Environmental Protection Agency

Exploitation: Drilling or other projects that may target proven or unproven reserves (such as probable or possible reserves), but that generally have a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field: An area comprised of multiple leases in close proximity to one another that typically produce from the same reservoirs and may or may not be produced under waterflood.

GAAP: Generally Accepted Accounting Principles in the United States of America

GHG: Greenhouse gas

Gross wells: The number of wells in which a working interest is owned.

Injection Well: A well employed for the introduction into an underground stratum of water, gas or other fluid under pressure.

LIBOR: London Interbank Offered Rate

MBbls : One thousand Bbls

MBoe: One thousand Boe

MBtu: One thousand Btu

MBoe/d: One thousand Boe per day

Mcf: One thousand cubic feet of natural gas

Mcf/d : One thousand cubic feet of natural gas per day

MMBoe: One million Boe

MMBtu: One million Btu

MMcf : One million cubic feet of natural gas

NASDAQ: National Association of Securities Dealers Automated Quotation System

NGLs: Natural gas liquids

Net Production: Production that is owned by us, less royalties and production due others.

Net Revenue Interest: A working interest owner's gross working interest in production, less the royalty, overriding royalty, production payment and net profits interests.

Net Well: The total of fractional working interests owned in a gross well.

NYMEX: New York Mercantile Exchange

Oil: Oil, condensate and natural gas liquids

Preferred Units: Class A Convertible Preferred Units

Preferred unitholders: The holders of Preferred Units

Productive Well: A well that is producing or that is mechanically capable of production.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves ("PUDs"): Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Realized Price: The cash market price, less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed. Reserves associated with recompletion are also referred to as "Behind Pipe."

Reserve: That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

SEC: Securities and Exchange Commission

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Spot Price : The cash market price without reduction for expected quality, transportation and demand adjustments.

Standardized Measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC, less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Because we are a limited partnership, we are generally not subject to federal or state income taxes and thus make no provision for federal or state income taxes in the calculation of our Standardized Measure. Standardized Measure does not give effect to derivative transactions.

Undeveloped Acreage: Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Unit: A contiguous geographic area that was established and approved by state oil and gas commissions for the express purpose of secondary recovery.

Unitization: The process of obtaining approval from working interest owners, mineral owners and regulatory agencies to conduct secondary (e.g., waterflooding) or tertiary operations.

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working Interest: The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover: Operations on a producing well to restore or increase production.

WTI: West Texas Intermediate, also called Texas light sweet, is defined as a type of crude oil used as a benchmark in oil pricing. It is the underlying commodity of NYMEX's oil future contracts.

NAMES OF ENTITIES

As used in this Form 10-K, unless we indicate otherwise:

- *"Founders" collectively refers to Charles R. Olmstead, S. Craig George and Jeffrey R. Olmstead;*
- *"our general partner" refers to Mid-Con Energy GP, LLC;*
- *"Mid-Con Affiliate" refers to Mid-Con Energy III, LLC and its subsidiaries, which is an affiliate of our general partner;*
- *"ME3 Oilfield Service" refers to ME3 Oilfield Service, LLC which is a wholly owned subsidiary of our Mid-Con Affiliate;*
- *"Mid-Con Energy Partners," the "partnership," "we," "our," "us," "company" or like terms when used refer to Mid-Con Energy Partners, LP, a Delaware limited partnership, and its subsidiaries;*
- *"Mid-Con Energy Operating" refers to Mid-Con Energy Operating, LLC, an affiliate of our general partner;*
- *"Mid-Con Energy Properties" refers to Mid-Con Energy Properties, LLC, our wholly owned subsidiary;*
- *"our predecessor" collectively refers to Mid-Con Energy Corporation, prior to June 30, 2009, and to Mid-Con Energy I, LLC and Mid-Con Energy II, LLC, on a combined basis, thereafter, our respective predecessors for accounting purposes; and*
- *"Yorktown" collectively refers to Yorktown Partners, LLC, Yorktown Energy Partners VI, LP, Yorktown Energy Partners VII, LP, Yorktown Energy Partners VIII, LP, Yorktown Energy Partners IX, LP and/or Yorktown Energy Partners X, LP.*

FORWARD-LOOKING STATEMENTS

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

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

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. "Business," Item 1A. "Risk Factors," Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. 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 Annual Report on Form 10-K 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 Annual Report on Form 10-K 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 and elsewhere in this Annual Report on Form 10-K. 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.

PART I

ITEM 1. BUSINESS

Mid-Con Energy Partners, LP is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on EOR. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our limited partner units ("common units") are listed on the NASDAQ Global Select Market under the symbol "MCEP."

Overview

We operate as one business segment engaged in the ownership, acquisition, exploitation and development of producing oil and natural gas properties. Our properties are located primarily in the Mid-Continent and Permian Basin regions of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma, and Texas within the Eastern Shelf of the Permian ("Permian"). During 2016, we sold all properties within our Hugoton core area. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

Our management team has significant industry experience, especially with waterflood projects and, as a result, our operations focus primarily on enhancing the development of producing oil properties through waterflooding. Waterflooding, a form of secondary oil recovery, works by displacing or "sweeping" oil to producing wellbores. Through the continued development of our existing properties and through future acquisitions, we seek to increase our reserves and production in order to make and, over time, increase distributions to our unitholders. Also, in order to enhance the stability of our cash flow for the benefit of our unitholders, we generally intend to hedge a portion of our production volumes through various commodity derivative contracts.

As of December 31, 2016, our total estimated proved reserves were approximately 19.2 MMBoe, of which approximately 95% were oil and 65% were proved developed, both on a Boe basis. As of December 31, 2016, we operated 100% of our properties through our affiliate, Mid-Con Energy Operating, and approximately 60% of our net proved reserves were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended December 31, 2016, was approximately 3,760 Boe/d and our total estimated proved reserves had an average reserve-to-production ratio of approximately 14 years.

The following table summarizes information by core area regarding our estimated net proved reserves, count of gross wells, reserve-to-production ratio and our average net production for the month ended December 31, 2016:

	Estimated Net Proved Reserves				December 2016 Average Production			Gross Active Wells		
Core Area	**MBoe**	**% Operated [1]**	**% Oil**	**% Proved Developed**	**Boe/d Gross**	**Boe/d Net**	**Reserve-to-Production Ratio [2] (Years)**	**Oil and Natural Gas Wells**	**Injection, Disposal or Water Supply Wells**	**Gross Shut-in or Waiting on Completion [3]**
Southern Oklahoma	2,720	100%	100%	74%	1,255	652	11	89	60	36
Northeastern Oklahoma	8,366	100%	97%	66%	1,530	1,274	18	240	78	310
Permian	7,766	100%	90%	59%	2,414	1,789	12	172	57	113
Other	379	100%	100%	76%	67	45	23	4	5	3
Total	19,231	100%	95%	65%	5,266	3,760	14	505	200	462

(1) Operated through our affiliate, Mid-Con Energy Operating.

(2) The reserve-to-production ratio is calculated by dividing estimated net proved reserves as of December 31, 2016, by average net production for the month ended December 31, 2016.

(3) As of December 31, 2016, no wells were waiting on completion and no shut-in wells were associated with proved developed reserves. Only 12 shut-in wells were associated with PUDs and were currently scheduled for return to production as part of planned secondary recovery projects. No wells classified as shut-in were due to operational factors, such as awaiting pipeline or facilities connections.

2016 Highlights

Cost Reductions and Operational Efficiencies

Lease operating expenses ("LOE") of $15.35 per Boe in for the year ended December 31, 2016, decreased approximately 22% from the year ended December 31, 2015. General and administrative expenses ("G&A") of $4.66 per Boe for the year ended December 31, 2016, decreased approximately 15% from the year ended December 31, 2015.

Hugoton Core Area Divestiture

In July 2016, we closed our sale of oil and natural gas assets within the Hugoton core area for cash proceeds of approximately $17.6 million, including post-close adjustments. Net divestiture proceeds were used to reduce borrowings outstanding under our revolving credit facility.

Permian Bolt-On Acquisition

In August 2016, we closed on our acquisition of oil and natural gas assets in Nolan County, Texas ("Permian Bolt-On") for approximately $18.7 million, after post-closing purchase price adjustments. The acquisition was paid for in cash from proceeds from the Preferred Unit offering.

Preferred Units

In conjunction with the Permian Bolt-On acquisition, in August 2016, we completed a private offering of $25.0 million aggregate principal amount of Preferred Units. Proceeds were used to fund the Permian Bolt-On acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility.

Debt Reduction

We paid $58.0 million of outstanding debt during 2016, ending the year with a conforming borrowing base of $140.0 million. Our outstanding borrowings at December 31, 2016, were $122.0 million. Funds for debt repayment were provided by the Hugoton core area divestiture, remaining proceeds from the Preferred Unit offering in excess of the Permian Bolt-On acquisition, cash settlements received from the early termination of commodity derivatives (net of premiums) and cash flows from operations.

Our Business Strategies

Our primary business objective is to generate stable cash flows, which we expect will allow us to make quarterly cash distributions to our unitholders and, over time, to increase our quarterly cash distributions. In addition to our hedging strategy described below, we intend to execute the following business strategies:

- ***Continue exploitation of our existing properties to maximize production.*** We plan to continue exploiting our proved reserves to maximize production, primarily through waterflood projects and through various oil recovery methods, including workovers, conventional hydraulic fracturing, re-stimulations, recompletions, infill drilling and other optimization activities. We expect to continue these activities in order to maximize economic production volumes.
- ***Pursue acquisitions of long-lived, low-risk producing properties with upside potential.*** We seek to acquire properties with long-lived reserves, low production decline rates and low-risk development potential. We also will seek to acquire properties within mature oil fields with opportunities for incremental improvements in oil recovery through waterfloods and other recovery techniques, which we believe will offer us additional potential to increase reserves, economic production volumes and cash flows.
- ***Capitalize on our relationship with our Mid-Con Affiliate for favorable acquisition opportunities.*** We expect that our Mid-Con Affiliate will continue to invest capital and technical staff resources to acquire and develop properties with existing waterfloods and to identify, acquire, form and develop new waterflood projects on those properties. Through this relationship with our Mid-Con Affiliate, we plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing properties, we expect that our Mid-Con Affiliate will offer to sell properties to us from time to time. We believe that the opportunity to acquire properties from our Mid-Con Affiliate provides us with a strategic advantage over those of our competitors who must bear a greater share of development risks themselves.

- ***Maintain operational control and a focus on cost effectiveness in all our operations.*** As of December 31, 2016, Mid-Con Energy Operating operated 100% of our properties, calculated on a Boe basis. We plan to continue exercising this level of operational control over our existing properties and favor acquisitions of operated properties in order to manage the timing and levels of our capital expenditures, development activities and operating costs.
- ***Reduce the impact of commodity price volatility on our cash flows through a disciplined commodity hedging strategy.*** We seek to reduce the impact of commodity price volatility on our cash flows by maintaining a portfolio of commodity derivative contracts to help offset the underlying volatility of oil and natural gas prices. As opposed to entering into commodity derivative contracts at predetermined times or on prescribed terms, we enter into commodity derivative contracts in connection with material increases in our estimated production, at times when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the prices, percentages of our hedged production volumes or the duration of our commodity derivative contracts when circumstances suggest that it is prudent to do so.
- ***Employ equity as our primary currency for acquisitions.*** We intend to maintain an equity-weighted bias towards acquisition financing. Although the cost of equity financing is generally more costly than debt financing, we believe the resulting conservatism and financial flexibility merit the incremental expense of continuing to rely on equity as our primary currency to fund acquisitions.

Our Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies and achieve our objective of generating and growing cash available for distribution:

- ***An asset portfolio largely consisting of properties with existing waterflood projects with proved reserves, of which approximately 95% are oil, and relatively predictable production profiles that provide growth potential through ongoing response to waterflooding and that have modest capital requirements.*** Our properties consist of interests in mature fields located in Oklahoma and Texas that have well-understood geologic features, relatively predictable production profiles and modest capital requirements, which we believe make them well-suited for waterflood development and for our objective of generating stable cash flows. Currently, approximately 60% of our net proved reserves on a Boe basis are being produced under waterflood. Based on production estimates from our December 31, 2016, audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 16.5% for 2017 and, on a compounded average decline basis, approximately 10.8% for the subsequent five years and approximately 9.8% thereafter. Further, we believe that a substantial majority of the capital required for growth from our existing properties has already been spent. As a result, these properties have relatively predictable production profiles and production growth potential with modest capital requirements.
- ***The ability to further exploit existing mature properties by utilizing our waterflood expertise.*** We have actively operated a significant portion our properties since 2005 and have a history of exploiting proved reserves to maximize production, primarily through waterflood projects. Over the last ten years, we, along with our affiliates, have identified, initiated, acquired, formed and developed approximately 22% of all new waterflood projects in the state of Oklahoma, while the next most active competitor formed only 7% of all new waterfloods. Furthermore, our experience in the Mid-Continent allows us to exploit synergies developed by applying knowledge of field, reservoir and play characteristics throughout North America. We believe that our expertise in secondary recovery techniques will increase the level of production from certain properties in our portfolio, particularly from existing waterflood projects, which, over time, may increase our cash flows.
- ***Acquisition opportunities that are consistent with our criteria of predictable production profiles with upside potential that may arise as a result of our relationship with the Mid-Con Affiliate.*** We expect that our Mid-Con Affiliate will continue to invest capital and technical staff resources to acquire and develop properties with existing waterfloods and to identify, acquire, form and develop new waterflood projects on those properties. Through this relationship with our Mid-Con Affiliate, we plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing properties, we expect that our Mid-Con Affiliate will offer to sell properties to us from time to time. We believe that the opportunity to acquire properties from our Mid-Con Affiliate provides us with a strategic advantage over those of our competitors who must bear a greater share of development risks themselves.

- ***Access to the collective expertise of Yorktown's employees and their extensive network of industry relationships through our relationship with Yorktown.*** Yorktown is a private investment firm focused on investments in the energy sector with more than $5.0 billion in assets under management. With their decades of investment experience in the oil and natural gas industry and their extensive network of industry relationships, Yorktown's employees are well positioned to assist us in identifying and evaluating acquisition opportunities and in making strategic decisions.
- ***Mid-Con Energy Operating operates 100% of our properties, which allows them to control our operating costs and capital expenditures*** . As of December 31, 2016, Mid-Con Energy Operating operated 100% of our properties, as calculated on a Boe basis, which allowed it to control our operating costs and capital expenditures. We expect to continue exercising this level of operational control over our properties, including any properties we acquire through future acquisitions, which allows us to better manage our operating costs and capital expenditures. This substantial operational control of our producing properties also allows us to maximize the value of our properties, helps us stabilize our cash flows and affords us better control over the timing and costs of our operations.
- ***The range and depth of our technical and operational expertise allows us to expand both geographically and operationally to achieve our goals.*** We have assembled a senior team of geologists, engineers, landmen, accountants and operational personnel that have been successful in developing a significant number of new waterflood projects. Collectively, our management and employees have prior waterflood experience in over 200 waterflood projects located in 12 states. Through our affiliate, Mid-Con Energy Operating, we have a team of over 70 employees, with senior leadership in all production disciplines, and we have recruited a select group of younger professionals that are being trained in our waterflood specialty. With this expertise and depth, we believe this team has the ability to generate new waterflood projects that may become future acquisition opportunities for us. Beyond our core strength of waterflood development, our range and depth of expertise will allow us to expand both geographically and operationally. Although our projects to date have been focused on waterfloods in the Mid-Continent and Permian regions, our management and operational employees have significant oil and natural gas experience in many other regions of the United States. Our wealth of experience enables us to pursue other types of exploitation opportunities, such as infill drilling projects that could significantly contribute to our strategy of generating stable cash flow and increasing our quarterly cash distributions over time.

Hedging Strategy

Our hedging program's objective is to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and NYMEX-WTI futures prices. As of December 31, 2016, we had commodity derivative contracts covering approximately 75%, 43% and 12% of our estimated oil production (estimate calculated based on the mid-point of our 2017 Boe production guidance as released on February 28, 2017 and multiplied by a 93% oil weighting based on fourth quarter 2016 reported production volumes) for calendar years 2017, 2018 and 2019, respectively. At December 31, 2016, our derivative contracts had maturities through 2019 and were comprised of commodity price swap, call, put and collar contracts.

In addition to our primary hedging strategy as described above, we also intend to enter into additional commodity derivative contracts in connection with material increases in our estimated production and at times when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. It is not our strategy to enter into commodity derivative contracts at predetermined times or on prescribed terms. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the prices, percentages of our hedged production volumes or the duration of our commodity derivative contracts when circumstances suggest that it is prudent to do so.

By removing a portion of price volatility associated with our estimated future oil production, we have mitigated, but not eliminated, the potential effects of changing oil prices on our cash flows from operations for those periods. For a further description of our commodity derivative contracts, please see Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information **.**

Our Principal Business Relationships

Our Relationship with our Mid-Con Affiliate

Our Mid-Con Affiliate acquires and develops oil and natural gas properties that are either undeveloped or that may require significant capital investment and development efforts before they meet our criteria for ownership. As these development projects mature, we expect to have the opportunity to acquire some of these properties from our Mid-Con Affiliate. Through this relationship with our Mid-Con Affiliate, we plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. However, our Mid-Con Affiliate may not be successful in identifying or consummating acquisitions or in successfully developing the new properties they acquire. Further, our Mid-Con Affiliate is not obligated to sell any properties to us, and they are not prohibited from competing with us to acquire oil and natural gas properties.

Services Agreement

We are party to a services agreement with Mid-Con Energy Operating, pursuant to which, Mid-Con Energy Operating provides certain services to us, our subsidiaries and our general partner, 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. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate back to us. Mid-Con Energy Operating will not be liable to us for its performance of, or failure to perform, services under the services agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are parties to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead associated with operating our properties. We and those third parties also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements.

Oilfield Services

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

Our Relationship with Yorktown

We have a valuable relationship with Yorktown, a private investment firm founded in 1991 and focused on investments in the energy sector. Since 2004, Yorktown has made several equity investments in our predecessor. Peter A. Leidel, a principal of Yorktown, serves on our Board of Directors.

Yorktown currently has more than $5.0 billion in assets under management and Yorktown's employees have extensive investment experience in the oil and natural gas industry. Yorktown's employees review a large number of potential acquisitions and are involved in decisions relating to the acquisition and disposition of oil and natural gas assets by the various portfolio companies in which Yorktown owns interests. With their extensive investment experience in the oil and natural gas industry and their extensive network of industry relationships, Yorktown's employees are well positioned to assist us in identifying and evaluating acquisition opportunities and in making strategic decisions. Yorktown is not obligated to sell any properties to us, and they are not prohibited from competing with us to acquire oil and natural gas properties. Investment funds managed by Yorktown manage numerous other portfolio companies, including our Mid-Con Affiliate, which is engaged in the oil and natural gas industry and, as a result, Yorktown may present acquisition opportunities to other Yorktown portfolio companies that compete with us.

Our Areas of Operation

As of December 31, 2016, our properties were primarily located in the Mid-Continent and Permian regions of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and Texas within the Eastern Shelf of the Permian. These core areas are generally composed of multiple waterflood units that are in close proximity to one another, produce from geologically similar reservoirs and utilize similar recovery methods. Focusing on these core areas allows us to apply our cumulative technical and operational knowledge to ongoing property development and to better predict future rates of recovery. For a discussion of the properties in our core areas, please see "Summary of Oil Properties and Projects."

Our properties consist of mature, legacy onshore oil reservoirs of which approximately 60% of the net proved reserves are being produced under waterflooding, on a Boe basis. Our properties include multiple waterflood projects with varying degrees of maturity.

We own an average working interest of approximately 91% in 505 gross (455 net) producing wells, 158 gross (134 net) injection wells, 42 gross (40 net) water supply or disposal wells, and 462 gross (437 net) wells shut-in. We operate 100% of our properties by value, as calculated using our estimated net proved reserves as of December 31, 2016. Approximately 98% of our revenue was derived from the proceeds of oil production.

Our estimated proved reserves as of December 31, 2016, were approximately 19.2 MMBoe, of which approximately 95% were oil and approximately 65% were proved developed, both on a Boe basis. For the month ended December 31, 2016, our average net production was approximately 3,760 Boe/d.

The following table shows our estimated net proved reserves for our core areas, based on a reserve report prepared by our internal reserve engineers and audited by Cawley, Gillespie & Associates, Inc. ("CG&A"), our independent petroleum engineers, as of December 31, 2016, and certain unaudited information regarding production and sales of oil and natural gas with respect to such properties:

	Average Net Production For the Month Ended December 31, 2016		Estimated Net Proved Reserves as of December 31, 2016					
							Standardized Measure	
Core Area	Net (Boe/d)	% of Total	MBoe	% of Total Proved Reserves	% Oil	% Proved Developed Reserves	Amount (1) ($ in millions)	% of Total
Southern Oklahoma	652	17%	2,720	14%	100%	74%	$ 19	12%
Northeastern Oklahoma	1,274	34%	8,366	44%	97%	66%	$ 56	36%
Permian	1,789	48%	7,766	40%	90%	59%	$ 78	50%
Other	45	1%	379	2%	100%	76%	$ 4	2%
Total	3,760	100%	19,231	100%	95%	65%	$ 157	100%

(1) Our estimated net proved reserves and Standardized Measure were computed by applying average 12-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable 12-month period, held constant throughout the life of the properties). These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The average 12-month index prices were $42.75 per Bbl for oil and $2.49 per MMBtu for natural gas for the 12 months ended December 31, 2016.

All proved undeveloped locations conform to SEC rules for recording proved undeveloped reserves. None of our proved undeveloped reserves as of December 31, 2016, have remained undeveloped for more than five years from the date the reserves were initially booked as proved undeveloped.

Summary of Oil Properties and Projects

Following is a summary of our estimated net proved reserves and our Standardized Measure as of December 31, 2016, and the average daily net production of our core areas for the month ended December 31, 2016.

Southern Oklahoma

Our Southern Oklahoma properties are located in Love and Carter Counties, Oklahoma. The Southern Oklahoma properties consist of six waterflood units operated by Mid-Con Energy Operating, which were unitized by Mid-Con Energy Operating or in conjunction with partners. During December 2016, our properties in these fields produced an average of 1,255 gross (652 net) Boe/d, and contained 2,720 MBoe of estimated net proved reserves. At December 31, 2016, we had an average working interest of approximately 66% in 89 producing, 55 injection and 5 water supply wells (gross). During 2016, we converted 1 gross injection well to a producing well and converted 1 producing well to an injection well.

Northeastern Oklahoma

Our Northeastern Oklahoma properties are located in four counties in Oklahoma: Seminole, Creek, Osage and Pawnee Counties. The majority of our Northeastern Oklahoma properties are being produced under waterflood and are operated by Mid-Con Energy Operating. During December 2016, our properties in these fields produced an average of 1,530 gross (1,274 net) Boe/d and contained 8,366 MBoe of estimated net proved reserves. At December 31, 2016, our average working interest in these properties was approximately 97% in 240 producing, 61 injection, 14 disposal and 3 water supply wells (gross). During 2016, we drilled 4 gross producing wells and changed the targeted injection formation in 3 gross wells.

Permian

Our Permian properties are located in ten counties in Texas: Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall and Taylor Counties. We acquired our first properties in November 2014 and in August 2016 we acquired additional oil and natural gas properties located in Nolan County, Texas. The Permian properties have four waterflood units operated by Mid-Con Energy Operating. During December 2016, our properties in these fields produced an average of 2,414 gross (1,789 net) Boe/d and contained 7,766 MBoe of estimated net proved reserves. At December 31, 2016, we had an average working interest of approximately 95% in 172 producing, 38 injection, 16 disposal and 3 water supply wells (gross). During 2016, we drilled 6 gross producing wells and converted 6 gross producing wells to injection wells.

Other Properties

The balance of the Partnership's properties, located in the Gulf Coast area of Texas, consists of operated properties which are under waterflood. During December 2016, our other properties produced an average of 67 gross (45 net) Boe/d and contained 379 MBoe of estimated net proved reserves. At December 31, 2016, we had an average working interest of approximately 100% in 4 producing, 4 injection and 1 water supply wells (gross). During 2016, we converted 1 gross producing well to an injection well.

Oil and Natural Gas Reserves and Production

Internal Controls Relating to Reserve Estimates

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our internal controls over the recording of reserves estimates require reserve estimates to be in compliance with the SEC rules, regulations, definitions and guidance. Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our reservoir engineering staff. Internal evaluations of our reserves are maintained in a secure reserve engineering database. Reserves are reviewed internally by our senior management on a quarterly basis. Our reserve estimates are audited by our independent third-party reserve engineers, CG&A, at least annually.

Our staff works closely with CG&A to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve audit process. To facilitate their audit of our reserves, we provide CG&A with any information they may request, including all of our reserve information as well as geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures, lease operating expenses, product pricing, production taxes and relevant economic criteria. We also make all of our pertinent personnel available to CG&A to respond to any questions they may have.

Technology Used to Establish Proved Reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and CG&A employ technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, injection data, seismic data and well test data. Reserves attributable to producing properties with sufficient production history are estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing properties with limited production history and for undeveloped locations are estimated using performance from analogous properties in the surrounding area and geologic data to assess the reservoir continuity. These properties were considered to be analogous based on production performance from the same formation and similar completion techniques.

Qualifications of Responsible Technical Persons

CG&A is an independent oil and natural gas consulting firm. No director, officer, or key employee of CG&A has any financial ownership in the Partnership, the Mid-Con Affiliate, Mid-Con Energy Operating or any of their respective affiliates. The compensation paid to CG&A for the audit is not contingent upon the results obtained and reported. The engineering audit presented in the CG&A report was overseen by W. Todd Brooker, Senior Vice President. Mr. Brooker has been a Petroleum Consultant for CG&A since 1992, and became Senior Vice President in 2011. His responsibilities include reserve and economic evaluations, fair market valuations, field studies, pipeline resource studies and acquisition and divestiture analysis. His reserve reports are routinely used for public company SEC disclosures. His experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures. Prior to CG&A he worked in Gulf of Mexico drilling and production engineering at Chevron USA. Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering. He is a registered professional engineer in Texas, No. 83462, and a member of the Society of Petroleum Engineers.

Dr. Chad B. Roller, Ph.D., is the Vice President of Exploitation of Mid-Con Energy Operating and has served in this role since March 2015. Dr. Roller previously served as Petroleum Engineer at Mid-Con Energy Operating and Royal Dutch Shell where his expertise includes waterflood development and EOR. Dr. Roller received his Ph.D. from Rice University in 2005 and Master of Science and Bachelor of Science degrees from the University of Oklahoma in 2002 and 2001, respectively.

Estimated Proved Reserves

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2016, based on reserve reports prepared by our reservoir engineering staff and audited by CG&A.

	Net Oil MBbls	Net Gas MMcf	Total Net MBoe
Reserve Data [(1)]			
Estimated proved developed reserves	11,733	4,141	12,423
Estimated proved undeveloped reserves	6,477	1,983	6,808
Total	18,210	6,124	19,231

(1) Our estimated net proved reserves were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $42.75 per Bbl for oil and $2.49 per MMBtu for natural gas at December 31, 2016. These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Average adjusted prices used were $40.03 per Bbl of oil and $1.99 per Mcf of natural gas.

The data in the table above represent estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil that are ultimately recovered. For a discussion of risks associated with internal reserve estimates, see "Item 1A. Risk Factors — Risks Related to Our Business." Our estimated proved reserves and future production rates rely on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure amounts should not be construed as the current market value of our estimated oil reserves. The 10% discount factor used to calculate Standardized Measure, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Production, Revenue and Price History

For a description of the Partnership's historical production, revenues and average sales prices and unit costs, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations."

Development of Proved Undeveloped Reserves

With respect to PUDs, we have established a development plan approved by the Vice President of Exploitation of Mid-Con Energy Operating that will result in converting the PUDs within five years from the initial disclosure of the reserves and the associated development capital requirements are equal to or less than the management-approved capital program on a year-by-year basis. If either of these criteria cease to be met, we remove the associated PUDs from our proved reserves disclosures.

Our development plan includes PUDs that are based upon qualitative and quantitative factors including estimated risk-based returns, current pricing forecasts, recent drilling results and waterflood responses. None of our PUDs at December 31, 2016, are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Consistent with the typical waterflood response time range of 6-18 months from initial development, the transfer of PUDs to the proved developed category is attributable to development costs incurred. During 2016, our capital expenditures for development (drilling, recompletion and conversion to injection) were approximately $5.5 million. Based on our current expectations of cash flows and the successful development activity in our Permian and Northeastern Oklahoma core areas, we plan to increase our 2017 capital spending budget for the development of our PUDs and look for development opportunities that can be funded from our cash flows from operations. For a more detailed discussion of our pro forma liquidity position, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

For the year ended December 31, 2016, our PUDs decreased from 7,090 MBoe to 6,808 MBoe. The decrease was primarily attributable to:

Conversion to proved developed reserves. We converted 1,351 MBoe from PUDs to proved developed reserves.

Revision of previous estimates . Commodity prices continued to decrease in 2016. The 12-month average price for crude oil decreased 15% from $50.28 per Bbl for 2015 compared to $42.75 per Bbl for 2016, while the 12-month average price for natural gas decreased 4% from $2.58 per MMBtu in 2015 compared to $2.49 per MMBtu for 2016. These decreases had an adverse impact on our PUDs estimates, resulting in downward reserve revisions of 185 MBoe during the year ending December 31, 2016. In response to the continued decrease in commodity prices throughout 2016, we further refined our development plans to concentrate on our core areas in Northeastern Oklahoma and the Permian. We saw positive oil production responses to water injection in our Northeastern Oklahoma and Permian areas resulting in the upward revision of 1,361 MBoe in PUDs from anticipated production performance of existing waterflood projects as well as development plans for additional waterflood projects in the Permian core area.

Purchases of reserves in place. These are additions to PUDs resulting from the acquisition of properties during the year ended December 31, 2016. The Permian Bolt-On acquisition, which closed on August 11, 2016, resulted in a positive change of 598 MBoe.

Sales of reserves in place. These are reductions to PUDs resulting from the disposition of properties during the year ended December 31, 2016. On July 28, 2016, the Hugoton core area properties were sold resulting in a downward revision of 705 MBoe.

The following table provides further details with respect to various factors that impacted the changes in our PUDs during 2016:

	Net Oil MBbls	Net Gas MMcf	Total Net MBoe
Proved Undeveloped Reserves as of December 31, 2015	6,746	2,065	7,090
Conversion to proved developed reserves	(1,303)	(287)	(1,351)
Revisions of previous estimates (1)	1,142	205	1,176
Acquisitions (2)	598	—	598
Sales of proved undeveloped reserves (3)	(706)	—	(705)
Reduction due to aged five or more years	—	—	—
Proved Undeveloped Reserves as of December 31, 2016	6,477	1,983	6,808

(1) Revisions of previous estimates represent changes in the previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

(2) Represents the purchase of PUDs as part of our Permian Bolt-On acquisition.

(3) Sale of our Hugoton core area oil and natural gas properties.

Development Activities

During 2016, we undertook a paced development program consisting of drilling approximately 10 gross (10 net) development wells, all of which reside in our Permian and Northeastern Oklahoma core areas. As part of our waterflood development program, approximately 11 gross (10 net) producing wells were converted to injectors or the targeted injection formation was changed with the majority of the conversions taking place in our Corsica Unit in the Permian core area. We will continue our development program and look for additional opportunities that can be funded from our cash flows from operations in 2017.

In our Permian core area, we drilled 6 gross (6 net) development wells in the Corsica Strawn, White Flats and Hard Rock fields. We continue to evaluate these properties for additional drilling opportunities and waterflood potential.

In our Northeastern Oklahoma core area, we drilled 4 gross (4 net) development wells in our Northeastern Oklahoma core area during 2016.

The following table sets forth information with respect to development activities during the periods indicated. The information should not be considered indicative of future performance nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Developmental wells:						
Productive	10	10	13	13	47	44
Injection	—	—	—	—	4	4
Water Supply	—	—	1	1	1	1
Dry	—	—	1	1	2	1
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	10	10	13	13	47	44
Injection	—	—	—	—	4	4
Water Supply	—	—	1	1	1	1
Dry	—	—	1	1	2	1
Total	10	10	15	15	54	50

Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2016. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own a working interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Gross Wells			Net Wells		
	Operated	Non-operated	Total	Operated	Non-operated	Total
Oil	504	1	505	455	—	455
Natural Gas	—	—	—	—	—	—
Injection	158	—	158	134	—	134
Disposal	30	—	30	30	—	30
Water Supply	12	—	12	10	—	10
Shut-in or Waiting on Completion [1]	462	—	462	437	—	437
Total	1,166	1	1,167	1,066	—	1,066

[1] As of December 31, 2016, no wells were waiting on completion and no shut-in wells were associated with proved developed reserves. Only 12 shut-in wells were associated with PUDs and were currently scheduled for return to production as part of planned secondary recovery projects. No wells classified as shut-in were due to operational factors, such as awaiting pipeline or facilities connections.

Production by Field

The following table sets forth our production for 2016, 2015 and 2014 from each of our fields that we represent as our core areas:

	Year Ended December 31,					
	2016		2015		2014	
Core Area	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Southern Oklahoma	274	8	354	10	428	8
Northeastern Oklahoma	458	126	482	165	344	73
Cleveland Field [1]	*255*	*8*	*244*	*9*	*178*	*12*
Hugoton [2]	103	3	273	14	269	20
Permian	536	417	502	379	53	37
Other	15	—	12	2	12	1
Total	1,386	554	1,623	570	1,106	139

[1] Northeastern Oklahoma includes the production from the Cleveland Field, which is the only field that represented 15% or more of our total estimated proved reserves at December 31, 2016, 2015 and 2014.

[2] Hugoton core area properties were divested in July 2016.

Developed Acreage

The following table sets forth information relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table. As of December 31, 2016, approximately 94% of our leasehold acreage was held by production:

	Developed Acreage		Undeveloped Acreage	
Core Area	Gross	Net	Gross	Net
Southern Oklahoma	8,744	6,454	—	—
Northeastern Oklahoma	7,248	6,699	—	—
Permian	16,918	16,168	2,381	2,083
Other	1,262	1,108	—	—
Total	34,172	30,429	2,381	2,083

The Southern Oklahoma and Northeastern Oklahoma core areas and other properties do not have any undeveloped acreage because all of our PUDs are related to new drilling or recompletion activities within currently producing areas of our developed acreage and represent in-fill or reduced spacing activity.

Delivery Commitments

We have no commitments to deliver a fixed and determinable quantity of our oil or natural gas production in the near future under our existing contracts.

Operations

General

We operate 100% of our properties, as calculated on a Boe basis as of December 31, 2016, through our affiliate, Mid-Con Energy Operating. We design and manage the development, recompletion or workover procedures for all of the wells we operate and supervise operation and maintenance activities. We do not own the drilling rigs or other oil field services equipment used for drilling or maintaining wells on the properties we operate.

We engage numerous independent contractors to provide all of the equipment and personnel associated with our drilling and maintenance activities, including well servicing, trucking, water hauling, bulldozing, and various downhole services (e.g., logging, cementing, perforating and acidizing). These services are short-term in duration (often being completed in less than a day) and are typically governed by a one-page service order that states only the parties' names, a brief description of the services and the price.

We also engage several independent contractors to provide hydraulic fracturing services. These services are usually completed in four to six hours utilizing lower pressures and volumes of fluid than are typically employed in multi-stage hydraulic fracturing jobs performed in connection with unconventional oil and natural gas shale plays. These services are not normally governed by long-term services contracts, but instead are generally performed under one-time service orders, which state the parties' name and the price. These service orders sometimes contain additional terms, for example, taxes, payment due dates, warranties and limitations of the contractor's liability to damages arising from the contractor's gross negligence or willful misconduct.

Geological and Engineering Services

Mid-Con Energy Operating employs production and reservoir engineers, geologists and land specialists, as well as field production supervisors. Through the services agreement, we have the direct operational support of a staff of over 30 petroleum professionals with significant technical expertise. We believe that this technical expertise, which includes extensive experience utilizing secondary recovery methods, particularly waterfloods, differentiates us from, and provides us with a competitive advantage over, many of our competitors. Please see Item 13. "Certain Relationships and Related Transactions, and Director Independence — Agreements and Transactions with Affiliates" for more information.

Administrative Services

Mid-Con Energy Operating provides us with management, administrative and operational services under the services agreement. We reimburse Mid-Con Energy Operating, on a cost basis, for the allocable expenses it incurs in performing these services. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. For a detailed description of the administrative services provided by Mid-Con Energy Operating pursuant to the services agreement, please see Item 13. "Certain Relationships and Related Transactions, and Director Independence — Agreements and Transactions with Affiliates."

Oil and Natural Gas Leases

The typical oil lease agreement covering our properties provides for the payment of royalties to the mineral owner for all hydrocarbons produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our properties range from less than 12.5% to 33.5%, resulting in a net revenue interest to us ranging from 66.5% to 87.5% on a 100% working interest basis. Our average net revenue interest is 76.5%. Most of our leases are held by production and do not require lease rental payments.

Principal Customers

For the year ended December 31, 2016, sales of oil and natural gas to four purchasers accounted for approximately 94% of our sales. The loss of any of our customers could temporarily delay production and sale of our oil and natural gas. If we were to lose any of our significant customers, we believe we could identify substitute customers to purchase the impacted production volumes. However, if any of our customers dramatically decreased or ceased purchasing oil from us, we may experience difficulty receiving comparable rates for our production volumes.

Hedging Activities

We continue to enter into commodity derivative contracts with unaffiliated third parties that are also members of our banking group to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. At December 31, 2016, our commodity derivative contracts had maturities through 2019 and were comprised of price swaps, calls, puts and collars. For a more detailed discussion of our hedging activities, see Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" and "Item 7A. Quantitative and Qualitative Disclosure About Market Risk — Commodity Price Risk."

Competition

We operate in a highly competitive environment for acquiring properties and securing trained personnel. Many of our competitors possess and employ financial resources substantially greater than ours, which can be particularly important in the areas in which we operate. These companies may have a greater ability to continue acquisition, and or exploration and production activities during periods of low commodity prices. Some of our competitors may also possess greater technical and personnel resources than us. As a result, our competitors may be able to pay more for properties, as well as evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

At times, we may also be affected by competition for drilling rigs, completion rigs and the availability of related equipment and services. In times past, the United States onshore oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and caused significant increases in the price for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation programs.

Title to Properties

Prior to completing an acquisition of producing oil properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener's and other errors and execute and record corrective assignments as necessary.

We initially conduct only a review of the titles to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We believe that we have satisfactory title to all of our material properties. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business.

Hydraulic Fracturing

Hydraulic fracturing has been a routine part of the completion process for the majority of the wells on our producing properties in Oklahoma and Texas for several decades. Most of our properties are dependent on our ability to hydraulically fracture the producing formations. We are currently conducting hydraulic fracturing activities in our Northeastern Oklahoma and Southern Oklahoma core areas. The majority of our leasehold acreage is currently held by production from existing wells. Therefore, fracturing is not currently required to maintain this acreage but it will be required in the future to develop the majority of our proved behind pipe and proved undeveloped reserves associated with this acreage. Nearly all of our proved behind pipe and proved undeveloped reserves associated with future drilling and recompletion projects, or 35% of our total estimated proved reserves as of December 31, 2016, will be subject to hydraulic fracturing. Although the cost of each well will vary, on average approximately 7% of the total cost of drilling and completing a well is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into and funded through our normal capital expenditure budget.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please see "Environmental Matters and Regulation —Water Discharges" in this section. For related risks to our unitholders, please see "Item 1A. Risk Factors — Risks Related to Our Business." Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Insurance

In accordance with industry practice, we maintain insurance against many potential operating risks to which our business could be exposed. Our coverage includes general liability, commercial umbrella liability, control of well, auto liability, property and equipment, worker's compensation and employer's liability, and directors and officers liability.

Currently, we have coverage for general liability insurance coverage, which includes coverage for sudden and accidental pollution liability and legal and contractual liabilities arising out of property damage and bodily injury, among other things. The insurance policies contain maximum policy limits and in most cases, deductibles that must be met prior to recovery and are subject to certain customary exclusions and limitations. This insurance coverage is in addition to the general and automobile liability policies and may be triggered if the general or automobile liability insurance policy limits are exceeded and exhausted. The control of well policy insures us for blowout risks associated with drilling, completing and operating our wells, including above ground pollution.

These policies do not provide coverage for all liabilities, and no assurance can be given that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, tribal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) govern the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil drilling and production activities; (iii) restrict the way we handle or dispose of our wastes; (iv) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require investigatory and remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (vi) impose obligations to reclaim and abandon wellsites. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of corrective or remedial obligations, and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the U.S. Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, storage, transport, drilling, disposal, and remediation requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, drilling disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. It is uncertain what impact, if any, the Trump administration will have on this trend. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot provide assurances that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, we can provide no assurance that we will not incur substantial costs in the future related to revised or additional environmental regulations that could have a material adverse effect on our business, financial condition and results of operations.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The federal Resource Conservation and Recovery Act, as amended, ("RCRA"), and comparable state statutes and their respective implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil, if properly handled, are exempt from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. However, it is possible that certain oil exploration, development and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to public health or the environment and to seek to recover from responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances or other pollutants released into the environment. Despite the so-called petroleum exclusion, we generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own and lease numerous properties that have been used for oil and/or natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Water Discharges

The federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and analogous state laws, impose restrictions and strict controls regarding the discharge of pollutants, including oil and hazardous substances, into state waters and federal navigable waters of the United States. The discharge of pollutants into federal or state waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state or tribal agency that has been delegated authority for the program by the EPA. Federal, state and tribal regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. Plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws required individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990, as amended ("OPA"), amends the Clean Water Act and establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the United States

The Safe Drinking Water Act, as amended, (the "SDWA") and analogous state laws impose requirements relating to our underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations related to permitting, testing, monitoring, record-keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water. We currently own a number of injection wells, used primarily for reinjection of produced waters that are subject to SDWA requirements.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We employ conventional hydraulic fracturing techniques to increase the productivity of certain of our properties. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into rock formations to fracture the surrounding rock and stimulate production. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has published guidance documents related to this regulatory authority. The Bureau of Land Management issued regulations, which have been challenged in court, for hydraulic fracturing on federal and tribal lands. In addition, Congress has considered federal regulation of hydraulic fracturing including disclosure of the chemicals used in the hydraulic fracturing process. Several states in which we operate, including Texas and Oklahoma, have adopted rules requiring the disclosure of certain information related to hydraulic fluids associated with wells that are hydraulically fractured. Additionally, some states and local governments have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, the State of Arkansas established a moratorium on waste water injection from hydraulic fracturing activities in certain areas due to concern that such injection was related to increased earthquake activity. Similarly, the State of Oklahoma has issued directives to shut-in or reduce the volume sent to disposal wells in the areas that have experienced recent earthquake activity. Other authorities are considering restrictions on the disposal of hydraulic fluids by deepwell injection. We follow applicable industry standard practices and legal requirements for groundwater protection in our hydraulic fracturing activities. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has completed a study of the potential environmental effects of hydraulic fracturing on drinking water resources and issued its final report in December 2016. The report concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances and identified conditions under which such impacts can be more frequent or severe. In June 2016, the EPA published final pretreatment standards for oil and natural gas extraction to ensure that wastewater from hydraulic fracturing activities is not sent to publicly owned treatment works. Subsequent rules have extended the implementation date for certain facilities that are subject to these standards. The U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Almost all of our hydraulic fracturing operations are conducted on vertical wells. The fracture treatments on these wells are much smaller and utilize much less water than what is typically used on most of the shale natural gas wells that are being drilled throughout the United States. We follow applicable industry standard practices and legal requirements for groundwater protection in our operations, subject to close supervision by state and federal regulators, which conduct many inspections during operations that include hydraulic fracturing. We minimize the use of water and dispose of the produced water into approved disposal or injection wells. We currently do not intentionally discharge water to the surface.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of our projects.

While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe that such requirements will have a material adverse effect on our operations. For example, on August 16, 2012, the EPA published final regulations under the Clean Air Act that, among other things, required additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOC"), and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations required the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations that occurred at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also established specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could increase our costs of development and production, though we do not expect these requirements to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, or CO_2, methane, and other greenhouse gases, or "GHG", present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHG under existing provisions of the federal Clean Air Act. These regulations include requirements to regulate emissions of GHG from motor vehicles, certain requirements for construction and operating permit reviews for GHG emissions from certain large stationary sources, rules requiring the reporting of GHG emissions from specified large GHG emission sources including operators of onshore oil and natural gas production and rules requiring so-called green completions of natural gas wells for wells constructed after January 2015. In addition, pursuant to President Obama's strategy to reduce methane emissions, the EPA recently issued new regulations that set methane and VOC emission standards for certain oil and natural gas facilities. The Paris Agreement, which was created by the United Nations Framework Convention on Climate Change, was signed by President Obama on August 29, 2016, and went into effect on November 4, 2016. The Paris Agreement requires participating countries to establish "nationally determined contributions" to mitigate climate change that "represent a progression over time" and are reported at five-year intervals. It is not clear at this time if the Trump administration will remain committed to the Paris Agreement or other measures that have been implemented to reduce GHG emissions.

We are currently monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule. Data collected from our initial GHG monitoring activities indicated that we do not currently exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level in the future, we will report the emissions beginning in the applicable period. Also, the U.S. Congress has from time to time considered legislation to reduce emissions of GHG and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHG. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require us to incur significant costs to reduce emissions of GHG associated with operations or could adversely affect demand for our production.

The EPA has also finalized regulations to reduce carbon dioxide emissions from the utility power sector, commonly referred to as the Clean Power Plan, which, if implemented, could reduce the demand for fossil fuels. The implementation of this rule has been stayed pending judicial review, and the Trump administration has indicated that it may revisit, modify or revoke the rule.

National Environmental Policy Act

Oil exploration, development and production activities that are located on federal lands or have a federal "nexus" are subject to the National Environmental Policy Act, as amended, ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that analyzes the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA may be required. This process has the potential to delay the development of oil projects.

Endangered Species Act

The federal Endangered Species Act ("ESA") may restrict activities that affect endangered or threatened species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While our facilities are located in areas that are not currently designated as habitat for endangered or threatened species, the designation of previously unidentified endangered or threatened species habitats could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to consider listing more than 250 species as endangered under the Endangered Species Act over a period of six years. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, ("OSHA"), and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations, and similar state statutes and regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Other Regulation of the Oil and Natural Gas Industry

General

Various aspects of our oil and natural gas operations are subject to extensive and frequently changing regulation as the activities of the oil and natural gas industry often are reviewed by legislators and regulators. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members.

The Federal Energy Regulatory Commission ("FERC") regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. FERC regulates interstate oil pipelines under the provisions of the Interstate Commerce Act ("ICA") as in effect in 1977 when ICA jurisdiction over oil pipelines was transferred to FERC, and the Energy Policy Act of 1992, or the EPA Act 1992. FERC is also authorized to prevent and sanction market manipulation in natural gas markets under the Energy Policy Act of 2005. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

In addition, the Federal Trade Commission ("FTC"), and the U.S. Commodity Futures Trading Commission ("CFTC") hold statutory authority to prevent market manipulation in oil and energy futures markets, respectively. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and natural gas markets and energy futures markets. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation. Failure to comply with such market rules, regulations and requirements could have a material adverse effect on our business, results of operations, and financial condition.

Oil and NGLs Transportation Rates

Our sales of crude oil, condensate and NGLs are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the ICA and EPA act 1992. The price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for oil, NGLs, and other products are regulated by the FERC, and in general, these rates must be cost-based or based on rates in effect in 1992, although FERC has established an indexing system for such transportation which allows such pipelines to take an annual inflation-based rate increase. Shippers may, however, contest rates that do not reflect costs of service. The FERC has also established market-based rates and settlement rates as alternative forms of ratemaking in certain circumstances.

In other instances involving intrastate-only transportation of oil, NGLs, and other products, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. Such pipelines may be subject to regulation by state regulatory agencies with respect to safety, rates and/or terms and conditions of service, including requirements for ratable takes or non-discriminatory access to pipeline services. The basis for intrastate regulation and the degree of regulatory oversight and scrutiny given to intrastate pipelines varies from state to state. Many states operate on a complaint-based system and state commissions have generally not initiated investigations of the rates or practices of liquids pipelines in the absence of a complaint.

Regulation of Oil and Natural Gas Exploration and Production

Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits, bonds and pollution liability insurance for the drilling of wells, regulating the location of wells, the method of drilling, casing, operating, plugging and abandoning wells, notice to surface owners and other third parties, and governing the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation of oil and natural gas resources, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing of such wells.

Oklahoma allows forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil wells generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill.

States also impose severance taxes and enforce requirements for obtaining drilling permits. For example, the State of Oklahoma currently imposes a production tax and an excise tax for oil and natural gas properties. A portion of our wells in Oklahoma currently receive a reduced production tax rate due to the Enhanced Recovery Project Gross Production Tax Exemption. Additionally, production tax rates vary by state. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future.

In 2012, there were numerous new and proposed regulations related to oil and natural gas exploration and production activities. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Pipeline Safety

While we do not own pipelines subject to safety regulation, we rely on such pipelines to deliver our production. Federal and state safety regulations have become increasingly more stringent over time and could affect the availability and cost of pipeline transportation to us.

Employees

The officers of our general partner manage our operations and activities. Neither we, our subsidiaries, nor our general partner have employees. Our general partner has entered into a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating will perform services for us, including the operation of our properties. Mid-Con Energy Operating has over 70 employees performing services for our operations and activities. We believe that Mid-Con Energy Operating has a satisfactory relationship with these employees.

Offices

In addition to our oil and natural gas properties discussed above, we lease corporate office space in Tulsa, Oklahoma, and lease field office space in Abilene, Texas. Our affiliate, Mid-Con Energy Operating, maintains a number of field office locations. We believe that our existing office facilities are adequate to meet our needs for the immediate future.

Financial Information

We operate our business as a single segment. Additionally, all of our properties are located in the United States and all of the related reserves are derived from properties located in the United States. Our financial information is included in the consolidated financial statements and the related notes included in "Item 8. Financial Statements and Supplementary Data."

Available Information

Our annual reports on Form 10–K, quarterly reports on Form 10–Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are made available free of charge on our website at www.midconenergypartners.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. These documents are also available on the SEC's website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC, 20549. No information from either the SEC's website or our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. This list is not exhaustive.

Risks Related to Our Business

We may not have sufficient cash available to make quarterly distributions on our units following the establishment of cash reserves and payment of expenses, including payments to our general partner.

In October 2015, our Board of Directors elected to suspend quarterly cash distributions on our common units. We may not have sufficient cash available for distribution each quarter in the future to make quarterly distributions on our units. Under the terms of our partnership agreement, the amount of cash available for distributions will be reduced by our operating expenses and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including development of our oil and natural gas properties, future debt service requirements and future cash distributions to our unitholders. The amount of cash that we distribute to our unitholders will depend principally on the cash we generate from operations, which will depend 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 inclusive of the net revenues from realized hedges;
- the amount and timing of settlements on our commodity derivative contracts;
- the ability to acquire additional oil and natural gas properties on economically acceptable terms;
- the ability to continue our development projects at economically attractive costs;
- the level of our capital expenditures, including scheduled and unexpected maintenance expenditures;
- the level of our operating costs, including payments to our general partner; and
- the level of our interest expense, which depends on the amount of our outstanding indebtedness and the interest payable thereon.

We may not make cash distributions during periods when we record net income.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flows, including cash from reserves established by our general partner and borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions to our unitholders during periods when we record net losses and may not make cash distributions to our unitholders during periods when we record net income.

If oil prices decline further or remain at current levels for a prolonged period, or if there is an increase in the differential between the NYMEX-WTI or other benchmark prices of oil and the wellhead price we receive for our production, our cash flows from operations will decline, which could reduce the cash available for distribution.

Lower oil prices may decrease our revenues and therefore, our cash available for distribution to our unitholders. Prices for oil may fluctuate widely in response to relatively minor changes in supply of and demand for oil, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil;

- market expectations about future prices of oil;
- the price and quantity of imports of crude oil;
- overall domestic and global economic conditions;
- political and economic conditions in other oil producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- trading in oil derivative contracts;
- the level of consumer product demand;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the proximity, cost, availability and capacity of oil pipelines and other transportation facilities;
- the impact of the U.S. dollar exchange rates on oil prices; and
- the price and availability of alternative fuels.

Also, the prices that we receive for our oil production often reflect a regional discount, based on the location of the production, to the relevant benchmark prices, such as the NYMEX-WTI, that are used for calculating hedge positions. These discounts, if significant, could similarly reduce our cash available for distribution to our unitholders and adversely affect our financial condition.

In the past, we have raised our distribution levels on our common units in response to increased cash flow during periods of relatively high commodity prices. However, we have not been able to sustain those distributions. In October 2015, our Board of Directors elected to suspend quarterly cash distributions on our common units. There is no guarantee that we will reinstate distributions on our common units in the near future.

Volatile oil prices may significantly impact our business.

Historically, oil prices have been extremely volatile. For the five years ended December 31, 2016, front-month NYMEX-WTI oil futures prices ranged from a high of $110.53 per barrel to a low of $26.21 per barrel. The volatility of the energy markets make it extremely difficult to predict future oil price movements with any certainty.

If commodity prices decline further or remain at current levels for a prolonged period, production from a significant portion of our producing or development projects may become uneconomic and cause write downs of the value of our properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

If commodity prices decline further or remain at current levels for a prolonged period many of our producing or development projects may become uneconomic resulting in a downward adjustment of our reserve estimates, which could negatively impact our borrowing base under our current revolving credit facility, our ability to fund our operations or to pay distributions to our unitholders.

NYMEX-WTI oil prices have remained low, on a historical basis. These reduced prices are caused by many factors, including substantial increases in U.S. production and reserves from unconventional (shale) reservoirs, without offsetting increases in demand. This environment could cause the prices for oil to remain at current levels or fall to lower levels.

The low commodity prices during 2016 resulted in a downward adjustment to our estimated proved reserves for our properties and our Standardized Measure which decreased from approximately $191.4 million as of December 31, 2015, to $157.3 million as of December 31, 2016. Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and natural gas properties. We recognized approximately $0.9 million in non-cash impairment expense for the year ended December 31, 2016, as well as approximately $3.6 million in non-cash impairment expense related to the Hugoton core area divestiture to reduce the carrying amount of those assets to their fair value. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for additional impairments. We may incur impairment in the future which could have a material adverse effect on our results of operations in the period taken.

Our hedging strategy may be ineffective in mitigating the impact of commodity price volatility on our cash flows, which could result in financial losses or could reduce cash available for distribution.

Our hedging strategy is to enter into commodity derivative contracts covering a portion of our near-term estimated oil production. The prices at which we are able to enter into commodity derivative contracts covering our production in the future will be dependent upon oil futures prices at the time we enter into these transactions, which may be substantially higher or lower than current oil prices.

Our revolving credit facility prohibits us from entering into commodity derivative contracts with the purpose and effect of fixing prices covering all of our estimated future production, and we therefore retain the risk of a price decrease on our volumes which we are precluded from securing with commodity derivative contracts. Furthermore, we may be unable to enter into additional commodity derivative contracts during favorable market conditions and, thus, may be unable to lock in attractive future prices for our product sales. Finally, our revolving credit facility and associated amendments may cause us to enter into commodity derivative contracts at inopportune times.

Our hedging activities could result in cash losses and may limit the prices we would otherwise realize for our production, which could reduce our cash available for distribution.

Our hedging strategy may limit our ability to realize cash flows from commodity price increases. Many of our commodity derivative contracts require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays), we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity and our cash available for distribution to our unitholders.

Our hedging transactions expose us to counterparty credit risk and involve other risks.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a commodity derivative contract. Disruptions in the financial markets could lead to a sudden decrease in a counterparty's liquidity, which could impair its ability to perform under the terms of the commodity derivative contract and, accordingly, prevent us from realizing the benefit of the commodity derivative contract. Because we conduct our hedging activities exclusively with participants in our revolving credit facility, our net position on a counterparty by counterparty basis is generally that of a borrower.

As a result of the Dodd-Frank Wall Street Reform and Consumer Protection Act and other legislation, hedging transactions and many of our contract counterparties have come under increasing governmental oversight and regulations in recent years. Although we cannot predict the ultimate impact of these laws and the related rulemaking, some of which is ongoing, existing or future regulations may adversely affect the cost and availability of our hedging arrangements, including by causing our counterparties, which include lenders under our revolving credit facility, to curtail or cease their derivative activities.

Unless we replace the oil and natural gas reserves we produce, our revenues and production will decline, which would adversely affect our cash flows from operations and our ability to make distributions to our unitholders.

We may be unable to make quarterly distributions without substantial capital expenditures that maintain our asset base. Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production and, therefore, our cash flows and ability to make distributions are highly dependent on our success in economically finding or acquiring recoverable reserves and efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

Our operations require substantial capital expenditures, which will reduce our cash available for distribution and could materially affect our ability to make distributions to our unitholders.

We make and expect to continue to make substantial capital expenditures for the development, production and acquisition of oil and natural gas reserves. Some of these expenditures will reduce our cash available for distribution. If additional capital is needed, we may not be able to obtain debt or equity financing if revenues decrease as a result of lower oil and natural gas prices, or if we experience declines in our estimated reserves or production or for any other reason. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to advancement of our development projects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

Developing and producing oil and natural gas is a costly and high-risk activity with many uncertainties that could adversely affect our business, financial condition or results of operations and, as a result, our ability to make distributions to our unitholders.

The cost of developing and operating oil and natural gas properties, particularly under a waterflood, is often uncertain, and cost and timing factors can adversely affect the economics of a well. Our efforts may be uneconomical if we drill dry holes, or if our properties are productive but do not produce as much oil or natural gas as we had estimated. Furthermore, our producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of equipment, labor or other services;
- unexpected operational events and conditions;
- adverse weather conditions and natural disasters;
- injection plant or other facility or equipment malfunctions and equipment failures or accidents;
- title disputes;
- unitization difficulties;
- pipe or cement failures, casing collapses or other downhole failures;
- compliance with environmental and other governmental requirements;
- lost or damaged oilfield service tools;
- unusual or unexpected geological formations and reservoir pressure;
- loss of injection fluid circulation;
- restrictions in access to, or disposal of, water used or produced in drilling, completions and waterflood operations;
- costs or delays imposed by or resulting from compliance with regulatory requirements;
- fires, blowouts, surface craterings, explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations; and
- uncontrollable flows of oil or well fluids.

If any of these factors were to occur with respect to a particular property, we could lose all or a part of our investment in the property, or we could fail to realize the expected benefits from the property, either of which could materially and adversely affect our revenue and cash available for distribution to our unitholders.

We inject water into most of our properties to maintain and, in some instances, to increase the production of oil and natural gas. We may in the future employ other secondary or tertiary recovery methods in our operations. The additional production and reserves attributable to the use of secondary recovery methods and of tertiary recovery methods are inherently difficult to predict. If our recovery methods do not result in expected production levels, we may not realize an acceptable return on the investments we make to use such methods.

Hydraulic fracturing has been a part of the completion process for the majority of the wells on our producing properties, and most of our properties are dependent on our ability to hydraulically fracture the producing formations. We engage third-party contractors to provide hydraulic fracturing services and generally enter into service orders on a job-by-job basis. Some service orders limit the liability of these contractors. Hydraulic fracturing operations can result in surface spillage or, in rare cases, the underground migration of fracturing fluids. Any such spillage or migration could result in litigation, government fines and penalties or remediation or restoration obligations. Our current insurance policies provide some coverage for losses arising out of our hydraulic fracturing operations. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up activities, and total losses related to a spill or migration could exceed our per occurrence or aggregate policy limits. Any losses due to hydraulic fracturing that are not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our estimated proved reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering is complex, requiring subjective estimates of underground accumulations of oil and assumptions concerning future oil and natural gas prices, future production levels and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove inaccurate. For example, if the price used in our December 2016 reserve report had been $10.00 less per barrel for oil, then the Standardized Measure of our estimated proved reserves as of that date would have decreased from $157.3 million to $71.7 million.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could affect our business, results of operations and financial condition and our ability to make distributions to our unitholders.

The Standardized Measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil reserves.

The present value of future net cash flows from our proved reserves, or Standardized Measure, may not represent the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our estimated proved reserves on the 12-month average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, "Extractive Activities-Oil and Gas," may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

If we do not make acquisitions on economically acceptable terms, our future growth and ability to make or increase distributions will be limited.

Our ability to make and to increase distributions to our unitholders depends in part on our ability to make acquisitions that result in an increase in available cash per unit. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with their owners;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to acquire properties containing estimated proved reserves, our total level of estimated proved reserves will decline as a result of our production, and we will be limited in our ability to make cash distributions to our unitholders.

Any acquisitions we complete are subject to substantial risks that could reduce our ability to make distributions to unitholders.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil reserves. Even if we make acquisitions that we believe will increase available cash per unit, these acquisitions may nevertheless result in a decrease in available cash per unit. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, commodity prices, revenues, operating expenses and costs;
- an inability to successfully integrate the assets we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing assets; and
- the occurrence of other significant charges, such as the impairment of oil properties, goodwill or other intangible assets, asset devaluations or restructuring charges.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of properties acquired from third parties (as opposed to the Mid-Con Affiliate) may be incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition, given the time constraints imposed by most sellers. Even a detailed review of the properties owned by third parties and the records associated with such properties may not reveal existing or potential problems, nor will such a review permit us to become sufficiently familiar with such properties to assess fully the deficiencies and potential issues associated with such properties. We may not always be able to inspect every well on properties owned by third parties, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Adverse developments in our core areas would reduce our ability to make distributions to our unitholders.

We only own oil and natural gas properties and related assets, all of which are currently located in Oklahoma and Texas. An adverse development in the oil and natural gas business in these geographic areas could have an impact on our results of operations and cash available for distribution to our unitholders.

We are primarily dependent upon a small number of customers for our production sales and we may experience a temporary decline in revenues and production if we lose any of those customers.

The loss of any of our customers could temporarily delay production and sale of our oil and natural gas. If we were to lose any of our significant customers, we believe that we could identify substitute customers to purchase the impacted production volumes. However, if any of our customers dramatically decreased or ceased purchasing oil from us, we may have difficulty receiving comparable rates for our production volumes.

Sales of oil and natural gas to four purchasers accounted for approximately 94% of our sales for the year ended December 31, 2016. Our production is, and will continue to be, marketed by our affiliate, Mid-Con Energy Operating. By selling a substantial majority of our current production to a small concentration of customers we believe that we have obtained and will continue to receive more favorable pricing than would otherwise be available to us if smaller amounts had been sold to several purchasers based on posted prices. To the extent these significant customers reduce the volume of oil and natural gas they purchase from us, we could experience a temporary interruption in sales of, or may receive a lower price for, our production, and our revenues and cash available for distribution could decline which could adversely affect our ability to make cash distributions to our unitholders.

In addition, a failure by any of these significant customers, or any purchasers of our production, to perform their payment obligations to us could have a material adverse effect on our results of operations. To the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge in the earnings of that period for the probable loss and could suffer a material reduction in our liquidity and ability to make distributions to our unitholders.

Unitization difficulties may prevent us from developing certain properties or greatly increase the cost of their development.

Regulation of waterflood unit formation is typically governed by state law. In most states anywhere from 63% to 85% of the leasehold and mineral owners in a proposed unit area must consent to a unitization plan before the state regulatory body, which oversees issues related to unitization and well spacing, will issue a unitization order. Mid-Con Energy Operating may be required to dedicate significant amounts of time and financial resources to obtaining consents from other owners and the necessary approvals from the state regulatory agencies. Obtaining these consents and approvals may also delay our ability to begin developing our new waterflood projects and may prevent us from developing our properties in the way we desire.

Other owners of mineral rights may object to our waterfloods.

It is difficult to predict the movement of the injection fluids that we use in connection with waterflooding. It is possible that certain of these fluids may migrate out of our areas of operations and into neighboring properties, including properties whose mineral rights owners have not consented to participate in our operations. This may result in litigation in which the owners of these neighboring properties may allege, among other things, a trespass and may seek monetary damages and possibly injunctive relief, which could delay or even permanently halt our development of certain of our oil properties.

We might be unable to compete effectively with larger companies, which might adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with companies that possess and employ financial, technical and personnel resources substantially greater than ours. These companies may be able to pay more for properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities despite the currently depressed oil price environment and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations and our ability to make distributions to our unitholders.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests lying contiguous or adjacent to or adjoining our interests could take actions, such as drilling additional wells, that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves, and may inhibit our ability to further exploit and develop our reserves.

We may incur additional debt to enable us to pay our quarterly distributions, which may negatively affect our ability to pay future distributions or execute our business plan.

In October 2015, our Board of Directors elected to suspend quarterly cash distributions on our common units. The terms of our credit agreement require the pre-approval of our lenders in order to reinstate distributions on our common units, however in the case whereby our distributions were to be reinstated, we may from that point forward be unable to make future distributions without borrowing under our revolving credit facility. If we were to use borrowings under our revolving credit facility to pay distributions to our unitholders for an extended period of time rather than to fund capital expenditures and other activities relating to our operations, we may be unable to maintain or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on our future indebtedness to pay these distributions, would reduce our cash available to make distributions on our units and could have a material adverse effect on our business, financial condition and results of operations.

Our revolving credit facility has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions under certain circumstances, and requires us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our revolving credit facility that are not cured or waived within specific time periods, a significant portion of our indebtedness may become immediately due and payable, we could be prohibited from making distributions to our unitholders in the future, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our revolving credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our revolving credit facility, the lenders could seek to foreclose on our assets.

The total amount we are able to borrow under our revolving credit facility is limited by a borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts, as determined by our lenders in their sole discretion. The borrowing base is subject to redetermination on a semi-annual basis and more frequent redetermination in certain circumstances. If our lenders were to decrease our borrowing base to a level below our then outstanding borrowings, the amount exceeding the revised borrowing base could become immediately due and payable. The negative redetermination of our borrowing base could adversely affect our business, results of operations, financial condition and our ability to make distributions to our unitholders. Furthermore, in the future, we may be unable to access sufficient capital under our revolving credit facility as a result of any decrease in our borrowing base.

We may not be able to generate enough cash flows to meet our debt obligations.

We expect our earnings and cash flows to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flows may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flows from operations and to service our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flows from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;

- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot provide assurances that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flows to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our ability to service our indebtedness and our business, financial condition and results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in the exploration, development and production of our oil and natural gas properties, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets due to weather and adverse economic conditions have made it more difficult for us to obtain certain types of coverage. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and we cannot be sure the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and under-insured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders.

Our business depends in part on transportation, pipelines and refining facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our production and could harm our business.

The marketability of our production depends in part on the availability, proximity and capacity of pipelines, tanker trucks and other transportation methods, and refining facilities owned by third parties. The amount of oil that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of available capacity on such systems, tanker truck availability and extreme weather conditions. Also, the shipment of our oil on third party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or refining facility capacity could reduce our ability to market our oil production and harm our business. Our access to transportation options and the prices we receive for our production can also be affected by federal and state regulation, including regulation of oil production and transportation, and pipeline safety, as well by general economic conditions and changes in supply and demand. In addition, the third parties on whom we rely for transportation services are subject to complex federal, state, tribal and local laws that could adversely affect the cost, manner or feasibility of conducting our business.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHG present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHG under existing provisions of the federal Clean Air Act, including requirements to reduce emissions of GHG from motor vehicles, requirements associated with certain construction and operating permit reviews for GHG emissions from certain large stationary sources, reporting requirements for GHG emissions from specified large GHG emission sources, including certain owners and operators of onshore oil and natural gas production and rules requiring so-called green completions of natural gas wells constructed after January 2015. We are currently monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule. Data collected from our initial GHG monitoring activities indicated that we do not exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level in the future, we will report the emissions beginning in the applicable period. Also, the U.S. Congress has from time to time considered legislation to reduce emissions of GHG, and almost one-half of the states, either individually or through multi-state regional initiatives, have already begun implementing legal measures to reduce emissions of GHG. Pursuant to President Obama's strategy to reduce methane emissions, EPA recently issued new regulations that set methane and VOC emission standards for certain oil and natural gas facilities. In addition, under the Paris Agreement, which went into effect on November 4, 2016, the U.S. is required to establish increasingly stringent nationally determined contributions to mitigate climate change. It is unclear at this time if the Trump administration will remain committed to the Paris Agreement or the other measures that have been implemented to reduce GHG emissions. However, the adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require us to incur significant costs to reduce emissions of GHG associated with operations or could adversely affect demand for our production.

Regulation in response to seismic activity could increase our operating and compliance costs.

Recent earthquakes in northern and central Oklahoma and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. To date, these regulations have not adversely impacted our operations but could limit future development for our operations. The adoption and implementation of any new laws, rules, regulations, requests, or directives that restrict our ability to dispose of water, including by plugging back the depths of disposal wells, reducing the volume of oil and natural gas wastewater disposed in such wells, restricting disposal well locations, or by requiring us to shut down disposal wells, could have a material adverse effect on our ability to produce oil and natural gas economically, or at all, and accordingly, could materially and adversely affect our business, financial condition and results of operations.

Rules recently finalized regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA's final rule includes NSPS standards for completions of hydraulically fractured wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The new rules became effective October 15, 2012; however, a number of the requirements did not take immediate effect as the final rule establishes a phase-in period to allow for the manufacture and distribution of required emissions reduction technology. As an example, until December 31, 2014, owners and operators of hydraulically fractured gas wells could either flare their emissions or use emissions reduction technology called "green completions" technologies already deployed at wells. On or after January 1, 2015, all newly fractured wells were required to use green completions. Controls for certain storage vessels, pneumatic controllers, compressors, dehydrators and other equipment must be implemented immediately or phased-in over time, depending on the construction date and/or nature of the unit. We continue to evaluate the EPA's final rule, as it may require changes to our operations, including the installation of new emissions control equipment.

Our operations are subject to environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil development and production activities. These costs and liabilities could arise under a wide range of federal, state, tribal and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. Claims for damages to persons or property from private parties and governmental authorities may result from environmental and other impacts of our operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to make cash distributions to our unitholders could be adversely affected. For a detailed discussion please read "Item 1. Business —Environmental Matters and Regulation."

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used in the completion of unconventional wells in shale formations as well as tight conventional formations, including many of those that we complete and produce. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has published draft guidance documents, which the Bureau of Land Management issued regulations, for hydraulic fracturing on federal and tribal lands, which were subsequently challenged in court. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Many states in which we operate have adopted rules requiring well operators to publicly disclose certain information regarding hydraulic fracturing operations, including the chemical composition of any liquids used in the hydraulic fracturing process. Generally, certain proprietary information may be excluded from an operator's disclosure. Additionally, some states and local authorities have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in our development or production activities.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has completed a study of the potential environmental effects of hydraulic fracturing on drinking water resources and issued its final report in December 2016. The report concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances and identified conditions under which the impacts may be more frequent or severe. In June 2016, the EPA published final pretreatment standards for oil and gas extraction sources to ensure that wastewater from hydraulic fracturing activities is not sent to publicly owned treatment works. On April 13, 2012, the Department of Interior, the Department of Energy and the EPA issued a memorandum outlining a multi-agency collaboration on unconventional oil and natural gas research in response to the White House "Blueprint for a Secure Energy Future" and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas followed by a strategy for research and development issued in July 2014 and a report to the U.S. Congress issued in December 2015. The U.S. Government Accountability Office has issued multiple reports on hydraulic fracturing, including two reports concerning environmental and health risks and key environmental and public health requirements related to hydraulic fracturing in September 2012 and a report on reducing freshwater use in hydraulic fracturing in August 2015. More recently there have been reports linking the injection of produced fluids from hydraulic fracturing to earthquakes. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms. Any additional level of regulation could lead to operational delays or increased operating costs which could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and would increase our costs of doing business, resulting in a decrease of cash available for distributions to our unitholders.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may affect adversely our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations sectors, including to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, and to communicate with our employees and third-party partners. Any future cyber security attacks that affect our facilities, our customers and any financial data could lead to data corruption, communication interruption, or other disruptions in our development operations or planned business transactions, any of which could have a material adverse effect on our business. In addition, security cyber attacks on our customer and employee data may result in a financial loss and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results. Further, as cyber security attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber security attacks.

Risks Inherent in an Investment in Us

Our general partner controls us, and the Founders, our Mid-Con Affiliate and Yorktown own an approximate 19.0% interest in us. They have conflicts of interest with, and owe limited fiduciary duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner has control over all decisions related to our operations. Our general partner is controlled by Messrs. Charles R. Olmstead and Jeffrey R. Olmstead. As of December 31, 2016, the Founders, our Mid-Con Affiliate and Yorktown own an approximate 19.0% interest in us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners. All of the executive officers and non-independent directors of our general partner are also officers and/or directors of the Mid-Con Affiliate and will continue to have economic interests in, as well as management and fiduciary duties to, the Mid-Con Affiliate. Additionally, one of the directors of our general partner is a principal with Yorktown. As a result of these relationships, conflicts of interest may arise in the future between the Mid-Con Affiliate and Yorktown and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our limited partner unitholders. These potential conflicts include, among others:

- Our partnership agreement limits our general partner's liability, reduces its fiduciary duties and also restricts the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are consenting to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- Neither our partnership agreement nor any other agreement requires the Mid-Con Affiliate and Yorktown or their respective affiliates (other than our general partner) to pursue a business strategy that favors us. The officers and directors of the Mid-Con Affiliate and Yorktown and their respective affiliates (other than our general partner) have a fiduciary duty to make these decisions in the best interests of their respective equity holders, which may be contrary to our interests;
- The Mid-Con Affiliate and Yorktown and their affiliates are not limited in their ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;
- All of the executive officers of our general partner who provide services to us also devote a significant amount of time to the Mid-Con Affiliate and are compensated for those services rendered;
- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other businesses with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;
- We entered into a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides management, administrative and operational services to us, and Mid-Con Energy Operating will also provide these services to the Mid-Con Affiliate;
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- Our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Neither we nor our general partner have any employees, and we rely solely on Mid-Con Energy Operating to manage and operate our business. The management team of Mid-Con Energy Operating, which includes the individuals who manage us, also provides substantially similar services to the Mid-Con Affiliate, and thus is not solely focused on our business.

Neither we nor our general partner have any employees, and we rely solely on Mid-Con Energy Operating to provide management, administrative and operational services to us. Mid-Con Energy Operating provides substantially similar services and personnel to the Mid-Con Affiliate and, as a result, may not have sufficient human, technical and other resources to provide those services at a level that it would be able to provide to us if it did not provide similar services to these other entities. Additionally, Mid-Con Energy Operating may make internal decisions on how to allocate its available resources and expertise that may not always be in our best interest compared to those of the Mid-Con Affiliate or other affiliates of our general partner. There is no requirement that Mid-Con Energy Operating favor us over these other entities in providing its services. If the employees of Mid-Con Energy Operating do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. In addition, as with other yield-oriented securities, our unit price is impacted by the level of cash distributions to unitholders and implied distribution yield. This implied distribution yield is often used by investors to compare and rank similar yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity or incur debt.

Public unitholders do not have a priority right to receive distributions and are not entitled to receive any payments of arrearages.

Unlike many publicly traded partnerships, we do not have any incentive distribution rights or subordinated units. Because there are no subordinated units, our public unitholders are not senior in payment of distributions over any other parties, including the Founders or Yorktown. Public unitholders will not have any right to receive any payments of distribution arrearages in future periods.

The holders of our Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units, and could dilute or otherwise adversely affect the holders of our common units.

In August 2016, we issued 11,627,906 Preferred Units, which rank senior to the common units with respect to distribution rights and rights upon liquidation. Subject to certain exceptions, as long as any Preferred Units remain outstanding, we may not declare any distribution on our common units unless all accumulated and unpaid distributions have been declared and paid on the Preferred Units. In the event of our liquidation, winding-up or dissolution, the holders of the Preferred Units would have the right to receive proceeds from any such transaction before the holders of the common units. The payment of the liquidation preference could result in common unitholders not receiving any consideration if we were to liquidate, dissolve or wind-up, either voluntarily or involuntarily. Additionally, the existence of the liquidation preference may reduce the value of the common units, make it harder for us to issue and sell common units in the future, or prevent or delay a change in control.

Our obligation to pay distributions on the Preferred Units, or on the common units issued following the conversion of the Preferred Units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general partnership purposes. Also, as long as any Preferred Units are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding Preferred Units, voting together as a separate class, will be necessary for effecting or validating, among other things: (i) any action to be taken that adversely affects any of the rights, preferences or privileges of the Preferred Units, (ii) amending the terms of the Preferred Units, (iii) the issuance of any additional Preferred Units or equity security senior or pari passu in right of distribution or in liquidation to the Preferred Units, (iv) the ability to incur indebtedness (other than under the Partnership's existing credit facility or trade payables arising in the ordinary course of business) or (v) lift the suspension of the at-the-market offering program. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

In addition, the holders of our Preferred Units may convert the Preferred Units into common units on a one-for-one basis at any time after the six-month anniversary of the closing date, in whole or in part, subject to certain conversion thresholds. At any time after the fifth anniversary of the closing date, each holder of the Preferred Units shall have the right to cause the Partnership to redeem all or any portion of the outstanding Preferred Units at a price per Preferred Unit equal to the Unit Purchase Price of $2.15 as described in the purchase agreement for the Preferred Units. Immediately prior to the effectiveness of a change of control of the Partnership, each Preferred Unit holder may elect to (i) have such holder's Preferred Units converted into common units, plus accrued but unpaid distributions to the conversion date; or (ii) if the Partnership is the surviving entity of the change of control, continue to hold its Preferred Units. If a holder of Preferred Units does not elect to convert all of its Preferred Units into common units representing limited partner interests in the Partnership upon the effectiveness of a change of control, then, unless the Partnership is the surviving entity of the change of control, the Partnership shall redeem any remaining Preferred Units in cash.

If a substantial portion of the Preferred Units are converted into common units, common unitholders could experience significant dilution. Further, if holders of converted Preferred Units dispose of a substantial portion of such common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. These sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Units held by persons who our general partner determines are not eligible holders will be subject to redemption.

To comply with U.S. laws with respect to the ownership of interests in oil and natural gas leases on federal lands, we have adopted certain requirements regarding those investors who may own our common units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and natural gas leases on federal lands. As of the date hereof, Eligible Holder means:

- a citizen of the United States;
- a corporation organized under the laws of the United States or of any state thereof;
- a public body, including a municipality;
- an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof; or
- a limited partner whose nationality, citizenship or other related status would not, in the determination of our general partner, create a substantial risk of cancellation or forfeiture of any property in which we or our subsidiary has an interest.

Onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof. Unitholders who are not persons or entities who meet the requirements to be an Eligible Holder run the risk of having their common units redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our unitholders have limited voting rights and are not entitled to elect our general partner or its Board of Directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders have no right on an annual or ongoing basis to elect our general partner or its Board of Directors. The Board of Directors of our general partner, including the independent directors, is chosen entirely by Charles R. Olmstead and Jeffrey R. Olmstead, the voting members of our general partner, and not by our unitholders. Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if our unitholders are dissatisfied, it would be difficult to remove our general partner without its consent.

The vote of the holders of at least 66.67% of all outstanding units is required to remove our general partner. As of December 31, 2016, the Founders, our Mid-Con Affiliate and Yorktown own an approximate 19.0% interest in us, which will enable those holders, collectively, to make it difficult to remove our general partner.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the Founders from transferring all or a portion of their ownership interests in our general partner to a third party. The new owner of our general partner would then be in a position to replace the Board of Directors and officers of our general partner with their own choices and thereby influence the decisions made by the Board of Directors and officers in a manner that may not be aligned with the interests of our unitholders.

We may issue an unlimited number of additional units, including units that are senior to the common units, without unitholder approval, which would dilute unitholders' ownership interests.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our partnership agreement restricts the limited voting rights of unitholders, other than Yorktown, the preferred unitholders, our general partner and its affiliates, owning 20% or more of our common units, which may limit the ability of significant unitholders to influence the manner or direction of management.

Our partnership agreement restricts unitholders' limited voting rights by providing that any common units held by a person, entity or group owning 20% or more of any class of common units then outstanding, other than Yorktown, the preferred unitholders, our general partner, its affiliates, their transferees and persons who acquired such common units with the prior approval of the Board of Directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting unitholders' ability to influence the manner or direction of management.

Sales of our common units by the selling unitholders may cause our price to decline.

As of December 31, 2016, the Founders, our Mid-Con Affiliate and Yorktown own 5,405,496 common units and 360,000 units held by our general partner, or an approximate 19.0% interest in us. Sales of these units or of other substantial amounts of our common units in the public market, or the perception that these sales may occur, could cause the market price of our common units to decline. Sales of such units could also impair our ability to raise capital through the sale of additional common units.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for our obligations as if it was a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Our unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make distributions to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to us that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our partnership agreement requires that we distribute all of our available cash (as defined in our partnership agreement), which could limit our ability to grow our reserves and production and make acquisitions.

Our partnership agreement provides that we will distribute all of our available cash each quarter. As a result, we may be dependent on the issuance of additional common units and other partnership securities and borrowings to finance our growth. A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;

- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil and natural gas.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions, or growth capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to make or increase our per unit distribution level. There are no limitations in our partnership agreement or in our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement, or a change in current law, could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions which would be taxable as dividends for U.S. federal income tax purposes to the extent paid out of our current or accumulated earnings and profits as determined for U.S. federal income tax purposes, and no income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders and, therefore, negatively impact the value of an investment in our units.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time the U.S. President and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships. Additionally on January 19, 2017, the U.S. Treasury Department and the IRS publicly released the text of final regulations regarding qualifying income under Section 7704(d)(1)(E) of the Code, which were scheduled to be formally published in the Federal Register on January 24, 2017. On January 20, 2017, the Trump administration released a memorandum that generally delayed all pending regulations from publication in the Federal Register pending their review and approval. On January 24, 2017, the final regulations were published in the Federal Register despite the regulatory freeze mandated by the Trump administration. We believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the current law and the final regulations. However, there are no assurances that the final regulations will not be withdrawn in compliance with the temporary regulatory freeze. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted, eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Policy positions taken by the Trump administration and the U.S. Congress may result in significant changes in the rules governing U.S. federal income taxation, including changes to the tax rates, the ability to take certain deductions and/or the border adjustment tax. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and development are eliminated as a result of future legislation.

If the IRS contests any of the federal income tax positions we take, the market for our units may be adversely affected, and the costs of any IRS contest will reduce our cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may not agree with those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Recently enacted legislation, applicable to partnership tax years beginning after 2017, alters the procedures for auditing large partnerships and for assessing and collecting taxes due (including penalties and interest) as a result of a partnership-level federal income tax audit. Under the new rules, unless we are eligible to, and do, elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited tax year.

Our unitholders are required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us .

Because our unitholders are treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, our unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our units could be more or less than expected .

If our unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their adjusted tax basis in their units. Because prior distributions in excess of their allocable share of our total net taxable income decrease their tax basis in their units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation, depletion, amortization and Intangible Drilling Costs deduction recapture. In addition, because the amount realized may include a unitholder's share of our non-recourse liabilities, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts, ("IRAs"), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Prospective unitholders who are tax-exempt entities or non-U.S. persons should consult their tax advisor before investing in our units.

We will treat each purchaser of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units and because of other reasons, we will adopt depreciation, depletion and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to a unitholder's tax return.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Although recently issued final Treasury Regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, these regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change our method of allocating items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to affect a short sale of units may be considered as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to affect a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of units and could have a negative impact on the value of the units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. While we would continue our existence as a Delaware limited partnership, our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if special relief from the IRS is not available) for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. A technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a technical termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the tax year in which the termination occurs.

As a result of investing in our units, our unitholders may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future even if such unitholders do not live in those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We own property and conduct business in many states, some of which impose a personal income tax on individuals and impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. We may own property or conduct business in other states or foreign countries in the future. It is a unitholder's responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in "Item 1. Business —Our Areas of Operation, —Oil and Natural Gas Reserves and Production" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations" contained herein.

ITEM 3. 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. No amounts have been accrued at December 31, 2016.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the NASDAQ Global Select Market under the symbol "MCEP." At the close of business on February 24, 2017, based upon information received from our transfer agent and brokers and nominees, we had 36 limited partner unitholders of record. This number does not include owners for whom common units may be held in "street" names. The daily high and low sales prices per common unit for the period from January 1, 2016, through December 31, 2016, were $3.95 and $0.78, respectively.

The following table sets forth the range of the daily high and low sales prices per common unit and cash distributions to common unitholders for 2015 and 2016:

	Price Range		Cash Distribution
	High	Low	per Common Unit
2015:			
First Quarter	$ 7.21	$ 4.25	$ 0.125
Second Quarter	$ 6.97	$ 4.90	$ 0.125
Third Quarter	$ 4.99	$ 1.99	$ —
Fourth Quarter	$ 3.53	$ 1.05	$ —
2016:			
First Quarter	$ 1.93	$ 0.72	$ —
Second Quarter	$ 4.05	$ 1.70	$ —
Third Quarter	$ 3.08	$ 1.40	$ —
Fourth Quarter	$ 3.30	$ 1.93	$ —

Cash Distributions to Unitholders

In October 2015, prolonged declines in commodity prices prompted us to suspend cash distributions to common unitholders 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.

There is no assurance as to future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions and also prohibits us from making common unit cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining a future distributions.

Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash on a quarterly basis to unitholders of record on the applicable record date. Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- *less* , the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter to:
  - provide for the proper conduct of our business (including reserves for future capital expenditures, working capital and operating expenses) subsequent to that quarter;
  - comply with applicable laws, any of our loan agreements, security agreements, mortgage debt instruments or other agreements; or
  - provide funds for cash distributions to our preferred and common unitholders (including our general partner) for any one or more of the next four quarters;

- *plus* , if our general partner so determines, all or a portion of cash or cash equivalents on hand on the date of determination of available cash for the quarter.

See Note 10 to the Consolidated Financial Statements included in Item 8."Financial Statements and Supplementary Data" for additional information.

Securities Authorized for Issuance under Equity Compensation Plans

See "Item 11. Executive Compensation—Long-Term Incentive Program" for information regarding our equity compensation plans as of December 31, 2016.

Sales of Unregistered Securities

During the third quarter of 2016, we issued $25.0 million of Preferred Units. See Note 10 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information**.** The Preferred Units were issued in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(a)(2) thereof, as a transaction by an issuer not involving any public offering.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

This section presents our selected historical consolidated financial data. The selected financial data is derived from our audited financial statements. The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8. "Financial Statements and Supplementary Data," both contained herein.

The following table shows selected financial data for the periods and as of the dates indicated (in thousands except number of units):

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Revenues:					
Oil sales	$ 54,773	$ 72,520	$ 96,127	$ 85,080	$ 60,887
Natural gas sales	1,325	1,394	784	656	674
(Loss) gain on derivatives, net	(12,202)	22,366	29,361	(5,675)	5,714
Total revenues	43,896	96,280	126,272	80,061	67,275
Operating costs and expenses:					
Lease operating expenses	22,692	33,591	26,091	16,366	10,948
Oil and natural gas production taxes	2,893	3,487	6,325	3,817	1,965
Impairment of proved oil and natural gas properties	895	103,938	30,206	1,578	1,296
Impairment of proved oil and natural gas properties sold	3,578	—	—	—	—
Depreciation, depletion and amortization	23,074	34,174	21,877	14,421	10,324
Accretion of discount on asset retirement obligations	577	432	250	173	126
General and administrative	6,890	9,411	14,313	12,244	11,000
Total operating costs and expenses	60,599	185,033	99,062	48,599	35,659
Loss on sales of oil and natural gas properties, net	(560)	—	—	—	—
(Loss) income from operations	(17,263)	(88,753)	27,210	31,462	31,616
Other (expense) income:					
Interest income	12	11	13	9	10
Interest expense	(7,487)	(7,258)	(4,731)	(3,282)	(1,764)
Other (expense) income	(76)	547	—	—	—
Loss on settlement of ARO	—	(42)	—	—	—
Total other expense	(7,551)	(6,742)	(4,718)	(3,273)	(1,754)
Net (loss) income	(24,814)	(95,495)	22,492	28,189	29,862
Less: Distributions to preferred unitholders	1,249	—	—	—	—
Less: General partner's interest in net (loss) income	(295)	(1,146)	354	518	584
Limited partners' interest in net (loss) income	$ (25,768)	$ (94,349)	$ 22,138	$ 27,671	$ 29,278
Net (loss) income per limited partner unit:					
Basic	$ (0.86)	$ (3.18)	$ 0.98	$ 1.44	$ 1.62
Diluted	$ (0.86)	$ (3.18)	$ 0.98	$ 1.44	$ 1.62
Weighted average limited partner units outstanding:					
Limited partner units (basic)	29,834	29,642	22,499	19,234	18,049
Limited partner units (diluted)	29,834	29,642	22,518	19,249	18,049
Balance Sheet Data:					
Working capital	$ (591)	$ 1,308	$ 34,191	$ 1,435	$ 6,254
Total assets	$ 276,286	$ 327,086	$ 454,628	$ 190,083	$ 158,590
Long-term debt	$ 122,000	$ 150,000	$ 205,000	$ 112,000	$ 78,000
Class A convertible preferred units	$ 19,570	$ —	$ —	$ —	$ —
Total equity	$ 111,650	$ 130,498	$ 234,142	$ 66,788	$ 72,181
Other Financial Data:					
Adjusted EBITDA	$ 45,901	$ 54,982	$ 58,467	$ 59,973	$ 47,681

Non-GAAP Financial Measures

We include in this report our calculation of the non-GAAP financial measure Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) and net cash provided by operating activities, which are the GAAP financial measurements most directly comparable to Adjusted EBITDA. We define Adjusted EBITDA as net income (loss) plus:

- Interest expense, net;
- Depreciation, depletion and amortization;
- Accretion of discount on asset retirement obligations;
- (Gain) loss on derivatives, net;
- Cash settlements received (paid) for matured derivatives, net;
- Cash settlements received for early terminations and modifications of derivatives, net;
- Cash premiums received (paid) upon settlement of derivatives, net;
- Cash premiums received (paid) at inception of derivatives, net;
- Impairment of proved oil and natural gas properties;
- Impairment of proved oil and natural gas properties sold;
- Non-cash equity-based compensation; and
- (Gain) loss on sales of oil and natural gas properties, net.

Adjusted EBITDA should not be considered an alternative to net income (loss), operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. We believe Adjusted EBITDA is useful to investors because it is used by our management, by external users of 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. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. Furthermore, Adjusted EBITDA should not be viewed as indicative of the actual amount of cash that is available for distributions or that is planned to be distributed for a given period nor does it equate to available cash as defined in our partnership agreement.

The following table presents our reconciliation of Adjusted EBITDA to net income (loss), for each of the periods indicated.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in thousands)				
Net (loss) income	$ (24,814)	$ (95,495)	$ 22,492	$ 28,189	$ 29,862
Interest expense, net	7,475	7,248	4,718	3,273	1,754
Depreciation, depletion and amortization	23,074	34,174	21,877	14,421	10,324
Accretion of discount on asset retirement obligations	577	432	250	173	126
Loss (gain) on derivatives, net	12,202	(22,366)	(29,361)	5,675	(5,714)
Cash settlements received for matured derivatives, net	20,511	28,543	891	288	3,710
Cash settlements received for early terminations and modifications of derivatives, net	5,820	11,069	—	—	—
Cash premiums paid upon settlement of derivatives, net	(5,040)	(1,701)	—	—	—
Cash premiums paid at inception of derivatives, net	(121)	(14,064)	—	—	—
Impairment of proved oil and natural gas properties	895	103,938	30,206	1,578	1,296
Impairment of proved oil and natural gas properties sold	3,578	—	—	—	—
Non-cash equity-based compensation	1,184	3,204	7,394	6,376	6,323
Loss on sales of oil and natural gas properties, net	560	—	—	—	—
Adjusted EBITDA	$ 45,901	$ 54,982	$ 58,467	$ 59,973	$ 47,681

A reconciliation of Adjusted EBITDA to net cash provided by operating activities, our most directly comparable GAAP financial measure, for each of the periods indicated, is presented below:

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in thousands)				
Net cash provided by operating activities	$ 43,936	$ 48,425	$ 50,464	$ 56,634	$ 47,717
Debt issuance costs amortization	(1,372)	(1,156)	(348)	(168)	(131)
Change in working capital	(4,138)	425	3,633	234	(1,659)
Interest expense, net	7,475	7,248	4,718	3,273	1,754
Other	—	40	—	—	—
Adjusted EBITDA	$ 45,901	$ 54,982	$ 58,467	$ 59,973	$ 47,681

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with Item 8. "Financial Statements and Supplementary Data" contained herein.

Overview

Mid-Con Energy Partners, LP is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on EOR. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our limited partner units ("common units") are listed on the NASDAQ Global Select Market under the symbol "MCEP."

Our properties are located primarily in the Mid-Continent and Permian Basin regions of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma, and Texas within the Eastern Shelf of the Permian. During 2016, we sold all properties within our Hugoton core area. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

As of December 31, 2016, our total estimated proved reserves were approximately 19.2 MMBoe, of which approximately 95% were oil and 65% were proved developed, both on a Boe basis. As of December 31, 2016, we operated 100% of our properties through our affiliate, Mid-Con Energy Operating, and approximately 60% of our net proved reserves were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended December 31, 2016 was approximately 3,760 Boe/d and our total estimated proved reserves had a reserve-to-production ratio of approximately 14 years.

Overview of Results and Key Developments

Commodity Prices

Our revenues and net income (loss) are sensitive to oil and natural gas prices which have been, and are expected to continue to be, highly volatile. Average oil prices remained depressed during 2016. The front-month NYMEX-WTI futures price ranged from a low of approximately $26 per barrel to a high of approximately $54 per barrel, and averaged approximately $43 per barrel. Average oil prices during 2016 declined approximately 11% and 53% compared to 2015 and 2014, respectively.

Low Price Environment Initiatives

In response to the significant declines in benchmark oil prices, the Partnership conducted a comprehensive operating assessment of our portfolio in late 2015 to evaluate the economic viability of each well we operate. We remain focused on cost reductions, and ongoing initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of LOE and G&A. Based on this assessment, we elected to shut-in approximately 184 uneconomic wells, the majority of which were shut-in late January 2016. Cash operating costs per Boe, which include LOE, production taxes and cash general and administrative expenses, declined by approximately 16% year over year, highlighted by a 22% decrease in lease operating expenses per Boe.

Hugoton Core Area Divestiture

In July 2016, we completed the sale of the Hugoton core area properties for cash proceeds of approximately $17.6 million, including post-closing adjustments, and recognized a loss of approximately $0.6 million. These assets and liabilities were deemed to meet held-for-sale accounting criteria as of June 30, 2016, accordingly, we recognized impairment of approximately $3.6 million included in "Impairment of proved oil and natural gas properties sold" in our consolidated statements of operations." See Note 3 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information **.**

Permian Bolt-On Acquisition

In August 2016, we acquired oil and natural gas properties located in Nolan County, Texas for an aggregate purchase price of approximately $18.7 million, after post-closing purchase price adjustments. The acquisition was paid for in cash from proceeds from the Preferred Unit offering. See Note 3 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information **.**

Preferred Unit Offering

In conjunction with the Permian Bolt-On acquisition, in August 2016, we completed a private offering of $25.0 million aggregate principal amount of Preferred Units. Proceeds were used to fund the Permian Bolt-On acquisition and for general partnership purposes, including reduction of borrowings under our revolving credit facility. See Note 10 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information **.**

Revolving Credit Facility

The conforming borrowing base of our revolving credit facility increased from $105.0 million in effect after the closing of the Hugoton core area divestiture to $140.0 million established in conjunction with the Permian Bolt-On acquisition closed during August 2016. The conforming borrowing base was reaffirmed by our lender group at $140.0 million during our fall 2016 redetermination finalized in October 2016.

We reduced outstanding borrowings under our revolving credit facility by $58.0 million during 2016 to $122.0 million outstanding as of December 31, 2016. Funds for debt repayment were provided by the Hugoton core area divestiture, remaining proceeds from the Preferred Unit offering in excess of the Permian Bolt-On acquisition, cash settlements received from the early termination of commodity derivatives (net of premiums) and cash flows from operations.

See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Distributions

On November 14, 2016, we paid a cash distribution on the Preferred Units for the period from August 11, 2016, to September 30, 2016, of approximately $0.3 million . As announced on January 25, 2017, the Board of Directors of the general partner declared a distribution on the Preferred Units for the fourth quarter of 2016 of approximately $0.5 million, which were paid on February 14, 2017, to holders of record as of the close of business on February 7, 2017.

As of February 28, 2017, cash distributions on our common units continued to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions and also prohibits us from making common unit cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders.

Relocation of Corporate Headquarters

On June 10, 2016, we announced the relocation of our corporate headquarters from Dallas, Texas, to Tulsa, Oklahoma, and the closing of our Dallas office.

Appointment and Departure of Certain Officers

Mr. Charles L. McLawhorn III was named Vice President, General Counsel and Corporate Secretary of the general partner effective April 1, 2016, replacing Mr. Nathan Pekar who resigned on January 8, 2016.

Mr. Matthew R. Lewis was named Vice President and Chief Financial Officer of the general partner effective August 1, 2016, replacing Mr. Michael D. Peterson whose resignation was effective July 31, 2016.

Mr. Robert W. Berry retired from the Board of Directors of the general partner effective August 1, 2016.

Mr. S. Craig George resigned from the Board of Directors of the general partner effective January 31, 2017.

Mr. Wilkie S. Colyer Jr. was appointed to the Board of Directors of the general partner effective February 1, 2017.

Business Environment

The markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future, which means that the price of oil and natural gas may fluctuate widely. Sustained periods of low prices for oil and natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. In general, the average oil and natural gas prices were lower during the comparable periods of 2016 measured against 2015. Our average sales price per barrel of oil, excluding commodity derivative contracts, was \$39.52 , \$44.68 and \$86.45 for the years ended December 31, 2016, 2015 and 2014, respectively. The volatility in commodity prices has impacted our unit price. During 2016, our common unit price fluctuated between a closing low of \$0.78 per unit in February to a closing high of \$3.95 in April.

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. 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. Since then, we have entered into additional oil commodity derivative contracts covering a portion of our anticipated oil production through 2019.

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

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

How We Evaluate Our Operations

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which will provide 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 properties and pay distributions to our unitholders. Adjusted EBITDA is a non-U.S. GAAP measure and should not be considered an alternative to net income (loss), net cash provided by operating activities or any other performance or liquidity measure determined in accordance with U.S. GAAP. In addition, our calculations of Adjusted EBITDA are not necessarily comparable to EBITDA or Adjusted EBITDA as calculated by other companies. See Item 6. "Selected Financial Data—Non-GAAP Financial Measures."

Critical Accounting Policies and Estimates

Accounting policies we consider significant are summarized in Note 2 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" of this report. Certain accounting policies require management to make critical accounting estimates. Accounting estimates are considered critical if the nature of the estimates and assumptions involves a high degree of subjectivity and judgment concerning uncertain matters and the impact of the estimates and assumptions is material to our financial position or results of operations. Additional information regarding our critical estimates is provided below.

Derivative Contracts and Hedging Activities

Current accounting rules require that all derivative contracts, other than those that meet specific exclusions, be recorded at fair value. Quoted market prices are the best evidence of fair value. If quotations are not available, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or on other valuation techniques. We use certain pricing models to determine the fair value of our derivative contracts. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We compare our estimates of the fair values of our derivative contracts with those provided by our counterparties. There have been no significant differences. For additional information regarding derivatives, see Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data."

Revenue recognition

We follow the sales method of accounting for oil and natural gas revenues. Under this method, revenues are recognized based on our share of actual proceeds from oil and natural gas sold to purchasers. Natural gas revenues would not have been significantly altered for the period presented had the entitlements method of recognizing natural gas revenues been utilized. If reserves are not sufficient to recover natural gas overtake positions, a liability is recorded. We had no significant natural gas imbalances at December 31, 2016 or 2015. We do not extract NGLs from our natural gas production prior to the sale and transfer of title of the natural gas stream to our purchasers. While some of our purchasers extract NGLs from the natural gas stream sold by us to them, we have no ownership in such NGLs. Therefore we do not report NGLs in our production or proved reserves.

Successful Efforts Method of Accounting

Accounting for oil and natural gas properties under the successful efforts method of accounting requires management to make estimates that may have a material impact on our financial position as they determine the carrying amount of our oil and natural gas properties and the amount of depletion and impairment expense. We believe the following to be critical accounting estimates associated with the successful efforts method of accounting of our oil and natural gas properties:

Oil and Natural Gas Reserves

Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The estimates of our proved reserves as of December 31, 2016 are based on reserve reports prepared by our reservoir engineering staff and audited by CG&A. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years.

The accuracy of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgments of the individuals preparing the estimates. In addition, our proved reserve estimates are also a function of many assumptions, all of which could deviate significantly from actual results. For example, when the price of oil and natural gas increases, the economic lives of our properties are extended, thus increasing estimated proved reserve quantities and making certain projects economically viable. Likewise, if oil and natural gas prices decrease, the economic lives of our properties are reduced and certain projects may become uneconomic, reducing estimated proved reserve quantities. Oil and natural gas price volatility adds to the uncertainty of our reserve quantity estimates. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas and NGLs eventually recovered. For additional information regarding estimates of reserves, including the Standardized Measure of discounted future net cash flows, see "Supplementary Information" in Item 8. "Financial Statements and Supplementary Data" and see also Item 1. "Business."

Impairment of Oil and Natural Gas Properties

We review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value exceeds management's estimate of fair value. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flow is less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flow to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with NYMEX-WTI forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. We review our oil and natural gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base.

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 ARO are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well. 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 ARO on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Over time, the liability is accreted each period toward its future value and the capitalized cost is depleted as a component of development costs. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability. See Note 7 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Acquisitions

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

Results of Operations

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

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil sales	$ 54,773	$ 72,520	$ 96,127
Natural gas sales	$ 1,325	$ 1,394	$ 784
(Loss) gain on derivatives, net	$ (12,202)	$ 22,366	$ 29,361
Operating costs and expenses:			
Lease operating expenses	$ 22,692	$ 33,591	$ 26,091
Oil and natural gas production taxes	$ 2,893	$ 3,487	$ 6,325
Impairment of proved oil and natural gas properties	$ 895	$ 103,938	$ 30,206
Impairment of proved oil and natural gas properties sold	$ 3,578	$ —	$ —
Depreciation, depletion and amortization	$ 23,074	$ 34,174	$ 21,877
General and administrative [(1)]	$ 6,890	$ 9,411	$ 14,313
Interest expense	$ 7,487	$ 7,258	$ 4,731
Loss on sales of oil and natural gas properties, net	$ 560	$ —	$ —
Production (Unaudited):			
Oil (MBbls)	1,386	1,623	1,112
Natural gas (MMcf)	554	571	157
Total (MBoe)	1,478	1,718	1,138
Average net production (Boe/d)	4,038	4,707	3,118
Average sales price (Unaudited):			
Oil (per Bbl):			
Sales price	$ 39.52	$ 44.68	$ 86.45
Effect of net settlements on matured derivative instruments [(2)]	$ 8.40	$ 12.86	$ 0.80
Realized oil price after derivatives	$ 47.92	$ 57.54	$ 87.25
Natural gas (per Mcf):			
Sales price	$ 2.39	$ 2.44	$ 4.99
Average unit costs per Boe (Unaudited):			
Lease operating expenses	$ 15.35	$ 19.55	$ 22.93
Oil and natural gas production taxes	$ 1.96	$ 2.03	$ 5.56
Depreciation, depletion and amortization	$ 15.61	$ 19.89	$ 19.22
General and administrative expenses	$ 4.66	$ 5.48	$ 12.58

(1) General and administrative expenses include non-cash equity-based compensation of $1.2 million , $3.2 million , and $7.4 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(2) For the year ended December 31, 2016, effect of net settlements on matured derivative instruments does not include the $5.8 million received and the $1.5 million of deferred premiums paid upon early termination of previous oil derivative contracts in July 2016 or the related $2.8 million premiums paid at inception of the oil derivative contracts in January 2015. For year ended December 31, 2015, effect of net settlements on matured derivative instruments does not include the $11.1 million received from restructuring the previous oil derivative contracts in January 2015.

Factors Affecting the Comparability of the Historical Financial Results

The comparability of our results of operations among the periods presented is impacted by:

- The drilling of 10 wells in 2016, 14 wells in 2015 and 52 wells in 2014.
- Our acquisition in August 2016 of oil and natural gas properties located in Nolan County, Texas.
- Our divestiture in July 2016 of our Hugoton core area properties.
- The shut-in of 184 wells for economic reasons in early 2016; 65 of those shut-in wells were sold as part of our Hugoton core area divestiture in July 2016.
- The significant fluctuation in oil prices beginning in late 2014 and continuing through 2016.
- Our acquisition in November 2014 of oil properties located in Coke, Coleman, Fisher, Haskell, Jones, Kent, Nolan, Runnels, Stonewall, Taylor and Tom Green Counties, Texas ("Permian").
- Our acquisition in August 2014 of a waterflood unit in Liberty County, Texas.
- Our acquisition in August 2014 of an oil property located in Creek County, Oklahoma from our Mid-Con Affiliate.
- Our acquisition in May 2014 of additional working interests in some of our Southern Oklahoma core area properties.
- Our acquisition in February 2014 of oil properties located in Cimarron, Love and Texas Counties, Oklahoma and Potter County, Texas from our Mid-Con Affiliate.

As a result of the factors listed above, historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results.

Year Ended December 31, 2016 Compared with Year Ended December 31, 2015

We reported a net loss of approximately $24.8 million for the year ended December 31, 2016, compared to a net loss of approximately $95.5 million for the year ended December 31, 2015. The $70.7 million change was primarily attributable to lower impairment, depreciation, depletion and amortization expenses ("DD&A"), LOE, G&A and production taxes, partially offset by the unfavorable net effect of derivatives and lower oil and natural gas sales volumes and prices.

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2016, were approximately $56.1 million compared to approximately $73.9 million for the year ended December 31, 2015. The revenue decrease was primarily due to lower oil sales volumes combined with lower oil prices driven by market conditions. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the year ended December 31, 2016, was $39.52 compared to approximately $44.68 for the year ended December 31, 2015.

On average, our production volumes for the year ended December 31, 2016, were approximately 1,478 MBoe, or approximately 4,038 Boe/d. In comparison, our total production volumes for the year ended December 31, 2015, were approximately 1,718 MBoe, or approximately 4,707 Boe/d. The decrease in production volumes was primarily due to the shut-in of 184 gross wells, reduced capital spending and the Hugoton core area divestiture completed during the third quarter of 2016, partially offset by incremental volumes from the acquired Permian Bolt-On properties. Of the 184 wells shut-in for economic reasons in early 2016, approximately 65 wells were located in the recently divested Hugoton core area and the majority of the remaining wells continued to be shut-in at December 31, 2016.

Effects of Commodity Derivative Contracts. For the year ended December 31, 2016, we recorded a net loss of approximately $12.2 million which was comprised of approximately $38.5 million non-cash loss on changes in fair value of our commodity derivative contracts, approximately $20.5 million gain on net cash settlements of our commodity derivative contracts and $5.8 million net cash settlements for the early termination of commodity derivative contracts. For the year ended December 31, 2015, we recorded a net gain from our commodity derivative contracts of approximately $22.4 million , which was comprised of approximately $28.5 million gain on net cash settlements of our commodity derivative contracts, $11.1 million net cash settlements for the early termination of contracts and approximately $17.2 million non-cash loss on changes in fair value of our commodity derivative contracts. The non-cash loss on changes in fair value of derivative contracts of approximately $17.2 million included an $11.1 million impact of the gain from early termination of the contracts and a $3.6 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 year ended December 31, 2016, LOE was approximately $22.7 million , or approximately $15.35 per Boe, compared to approximately $33.6 million , or approximately $19.55 per Boe, for the year ended December 31, 2015. The decrease in total LOE and average cost per Boe for the year ended December 31, 2016, reflects the impact of company-wide cost savings initiatives including the shut-in of uneconomic wells, divestiture of properties with higher operating costs and the acquisition of properties with lower operating expenses.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas sales revenues and exclude the effects of our commodity derivative contracts. Production taxes for the year ended December 31, 2016, were approximately $2.9 million , or approximately $1.96 per Boe (effective tax rate of approximately 5.2%), compared to approximately $3.5 million , or approximately $2.03 per Boe (effective tax rate of approximately 4.7%), for the year ended December 31, 2015. The overall decrease in production taxes for the year ended December 31, 2016, was attributable to lower oil and natural gas revenues and to 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 a greater proportion of Northeastern Oklahoma production, which is subject to a reduced tax rate based on the EOR exemption. The effective tax rate for the year ended December 31, 2015, was lower due to the recoupment of approximately $0.8 million in cash production taxes previously paid for one of our Northeastern Oklahoma units. Excluding the effect of the amounts recouped from the EOR exemption that were attributable to prior periods, the effective tax rate for 2015 would have been 5.8%.

Impairment Expense. For the year ended December 31, 2016, we recorded a non-cash impairment charge of approximately $0.9 million due to revisions in reserve estimates in one of our Permian properties. For the year ended December 31, 2015, we recorded a non-cash impairment charge of approximately $103.9 million due to a significant decline in commodity prices.

Impairment Expense of Proved Oil and Natural Gas Properties Sold. For the year ended December 31, 2016, we recorded non-cash impairment of approximately $3.6 million related to the Hugoton core area divestiture. These assets and liabilities were deemed to meet held-for-sale accounting criteria as of June 30, 2016; therefore, we reduced the carrying amount of those assets to their fair value.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the year ended December 31, 2016, was approximately $23.1 million , or approximately $15.61 per Boe, compared to approximately $34.2 million , or approximately $19.89 per Boe, for the year ended December 31, 2015. The decrease in DD&A and DD&A per Boe was primarily due to the asset impairment recorded in the third and fourth quarters of 2015 which reduced the carrying value of our oil and natural gas properties.

General and Administrative Expenses. G&A was approximately $6.9 million or approximately $4.66 per Boe for the for the year ended December 31, 2016, compared to approximately $9.4 million , or approximately $5.48 per Boe, for the year ended December 31, 2015. The decrease in G&A for the year ended December 31, 2016, was primarily due to lower non-cash equity-based compensation costs resulting from the lower price of our common units and fewer units issued, lower payroll and non-recurring legal and professional expenses. G&A included non-cash equity-based compensation expenses of approximately $1.2 million and approximately $3.2 million for the years ended December 31, 2016, and 2015, respectively.

Interest Expense. Our interest expense for the year ended December 31, 2016, was approximately $7.5 million , compared to approximately $7.3 million for the year ended December 31, 2015. The increase in interest expense during the year ended December 31, 2016, was due to a higher effective interest rate as a result of the higher pricing grid, established during the fall 2015 redetermination, for periods when borrowing utilization was equal to or greater than 100% of the borrowing base then in effect.

Loss on Sales of Oil and Natural Gas Properties. On July 28, 2016, we sold our properties located in the Hugoton core area for proceeds of approximately $17.6 million , including post-closing adjustments, and recognized a loss of approximately $0.6 million . We also recorded a loss of approximately $3.6 million due to impairment upon recording the properties as held for sale as of June 30, 2016.

Year Ended December 31, 2015 Compared with Year Ended December 31, 2014

We reported net loss of approximately $95.5 million for the year ended December 31, 2015, compared to net income of approximately $22.5 million for the year ended December 31, 2014. The $118.0 million change was primarily attributable to higher impairment, lower oil sales prices and higher DD&A expense.

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2015, were approximately $73.9 million as compared to approximately $96.9 million for the year ended December 31, 2014. Despite the year over year production growth resulting from the acquisition of properties in 2014, revenues were negatively affected by lower oil and natural gas prices. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the year ended December 31, 2015, was approximately $44.68 compared to approximately $86.45 for the year ended December 31, 2014.

On average, our production volumes for the year ended December 31, 2015, were approximately 1,718 MBoe, or approximately 4,707 Boe/d. In comparison, our total production volumes for the year ended December 31, 2014, were approximately 1,138 MBoe, or approximately 3,118 Boe/d. The increase in production volumes was primarily due to acquisitions of additional oil properties in 2014.

Effects of Commodity Derivative Contracts. For the year ended December 31, 2015, we recorded a net gain from our commodity derivative contracts of approximately $22.4 million, which was comprised of approximately $28.5 million gain on net cash settlements of our commodity derivative contracts, $11.1 million net cash settlements for the early termination of contracts and approximately $17.2 million non-cash loss on changes in fair value of our commodity derivative contracts. The non-cash loss on changes in fair value of derivative contracts of approximately $17.2 million included an $11.1 million impact of the gain from early termination of the contracts and a $3.6 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. For the year ended December 31, 2014, we recorded a net gain from our commodity derivative contracts of approximately $29.4 million, which was comprised of approximately $28.5 million non-cash gain on changes in fair value of our commodity derivative contracts and approximately $0.9 million gain on net cash settlements of our commodity derivative contracts.

Lease Operating Expenses. For the year ended December 31, 2015, LOE was approximately $33.6 million, or $19.55 per Boe, compared to approximately $26.1 million, or approximately $22.93 per Boe, for the year ended December 31, 2014. The increase in total LOE for the year ended December 31, 2015, was primarily attributable to the acquisitions of additional oil properties in 2014. The decrease in average costs per Boe reflected the impact of our ongoing cost reduction initiatives combined with the November 2014 Permian acquisition, which added significantly lower LOE per Boe assets into our producing portfolio for a small portion of 2014 and for the full-year 2015.

Production Taxes. Production taxes are calculated as a percentage of our oil and natural gas revenues and exclude the effects of our commodity derivative contracts. Production taxes for the year ended December 31, 2015, were approximately $3.5 million, or approximately $2.03 per Boe (effective tax rate of approximately 4.7%), compared to approximately $6.3 million, or approximately $5.56 per Boe (effective tax rate of approximately 6.5%) for the year ended December 31, 2014. The overall decrease in production taxes for the year ended December 31, 2015, was attributable to lower oil and natural gas revenues and to the approval of an EOR Production Tax Exemption for one of our Northeastern Oklahoma units, including recoupment of approximately $0.8 million in cash production taxes previously paid. The EOR exemption will extend through March 2018. The decrease in production tax per Boe was primarily attributable to the 2014 acquisitions of properties in Texas that have a lower production tax rate as compared to our legacy properties in Oklahoma and to the effect of the EOR exemption. Excluding the effect of the amounts recouped from the EOR exemption that were attributable to prior periods, the effective tax rate for 2015 would have been 5.8%.

Impairment Expense. For the year ended December 31, 2015, we recorded a non-cash impairment charge of approximately $103.9 million due to a significant decline in commodity prices. For the year ended December 31, 2014, we recorded a non-cash impairment charge of approximately $30.2 million primarily in our Hugoton core area and also in our Southern Oklahoma core area due to reduced commodity prices and to a lesser degree, reduced reserve estimates.

Depreciation, Depletion and Amortization Expenses. DD&A on producing properties for the year ended December 31, 2015 was approximately $34.2 million, or approximately $19.89 per Boe, compared to approximately $21.9 million, or approximately $19.22 per Boe, for the year ended December 31, 2014. The increase in DD&A was primarily due to the increase in the total asset value of our oil and natural gas properties along with increased production from the acquisitions of additional oil properties in 2014. The increase in DD&A per Boe was due to higher depletion rates in some of the oil and gas properties acquired in 2014.

General and Administrative Expenses. G&A was approximately $9.4 million, or approximately $5.48 per Boe, for the year ended December 31, 2015, compared to approximately $14.3 million, or approximately $12.58 per Boe, for the year ended December 31, 2014. The decrease in G&A for the year ended December 31, 2015, was primarily due to lower non-cash equity-based compensation costs resulting from the lower price of our common units, lower payroll expense and lower non-recurring legal and professional services. G&A included non-cash equity-based compensation of approximately $3.2 million and approximately $7.4 million for the years ended December 31, 2015, and 2014, respectively.

Interest Expense. Our interest expense for the year ended December 31, 2015 was approximately $7.3 million, compared to approximately $4.7 million for the year ended December 31, 2014. The increase in interest expense in 2015 compared to 2014 was due to higher borrowings outstanding from our revolving credit facility resulting from acquisitions of oil properties in November 2014.

Liquidity and Capital Resources

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

Since November 2014, oil prices have been extremely volatile, impacting the way we conduct business. In response, we have implemented a number of adjustments to strengthen our financial position. 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. Since then, we have entered into additional oil commodity derivative contracts covering a portion of our anticipated oil production. At December 31, 2016, we had commodity derivative contracts that extend through 2019. In the third quarter 2015, we indefinitely suspended our quarterly cash distributions on common units. We have aggressively pursued cost reductions to improve profitability and maximize cash flows. Our primary cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of LOE and G&A. Additionally, we further reduced the Partnership's weighted average cash operating break-even costs per Boe with the July 2016 divestiture of our higher cost Hugoton core area and the August 2016 acquisition of the Permian Bolt-On properties which carry a lower cost profile on a relative basis.

Our liquidity position at December 31, 2016, consisted of approximately $2.4 million of available cash and $18.0 million of available borrowings under our revolving credit facility ($140.0 million borrowing base less $122.0 million of outstanding borrowings). Our borrowing base is redetermined in the spring and fall of each year. In October 2016, we completed the fall 2016 semi-annual borrowing base redetermination under our revolving credit facility. The lender group reaffirmed the existing conforming borrowing base of $140.0 million effective October 28, 2016. There were no changes to the terms or conditions of the credit agreement. See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures budget, meet our debt service requirements, and fund our other commitments and obligations. Although we currently expect our sources of cash to be sufficient to meet our near-term liquidity needs, there can be no assurance that our liquidity requirements will continue to be satisfied due to the discretion of our lenders to decrease our borrowing base. Due to the volatility of 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):

	Year Ended December 31,		
	2016	2015	2014
Operating activities	$ 43,936	$ 48,425	$ 50,464
Investing activities	$ (8,475)	$ (13,894)	$ (189,323)
Financing activities	$ (33,717)	$ (37,148)	$ 140,657

Operating Activities. Net cash provided by operating activities was approximately $43.9 million, $48.4 million and $50.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. The $4.5 million change from 2015 to 2016 was primarily attributable to decreased oil sales revenues resulting from lower prices and production in 2016, partially offset by lower LOE and G&A due to various cost saving initiatives. The $2.1 million change from 2014 to 2015 was primarily attributable to decreased oil sales revenues due to lower oil prices and a decrease in working capital, primarily related to lower accounts receivable as a result of lower oil and natural gas sales, offset by higher cash settlements on derivatives.

Investing Activities. Net cash used in investing activities was approximately $8.5 million, $13.9 million and $189.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. Cash used in investing activities during the year ended December 31, 2016, included approximately $18.7 million for the acquisitions of oil and natural gas properties in the Permian area, approximately $7.2 million of capital expenditures for drilling and completion activities primarily in our Permian and Northeastern Oklahoma core areas, partially offset by proceeds from the sale of our oil and natural gas properties in the Hugoton core area of approximately $17.6 million. Cash used in investing activities during the year ended December 31, 2015, included approximately $13.9 million of capital expenditures, primarily for drilling, development and completion activities. Cash used for investing activities during 2014 included approximately $155.4 million for the acquisition of oil properties and additional working interests.

Financing Activities. Net cash (used in) and provided by financing activities was approximately ($33.7 million), ($37.1 million) and $140.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. Net cash used in financing activities during the year ended December 31, 2016, included payments on our revolving credit facility of approximately $58.0 million and a distribution to preferred unitholders of approximately $0.3 million, offset by net proceeds of approximately $24.6 million received from the sale of Preferred Units. Net cash used in financing activities during the year ended December 31, 2015, included net payments on our revolving credit facility of approximately $25.0 million, distributions to common unitholders of approximately $11.3 million, debt issuance costs of approximately $0.7 million and approximately $0.1 million of incremental offering costs from our November 2014 public offering. Net cash provided by financing activities during the year ended December 31, 2014, included net proceeds of approximately $96.0 million from our November 2014 equity offering which was used to finance the acquisition of multiple oil properties in the Permian, approximately $93.0 million of net proceeds from our revolving credit facility which were used to finance a portion of our 2014 acquisitions, approximately $44.6 million of distributions to common unitholders.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size of our asset base. The primary purpose of growth capital is to acquire and develop producing assets that allow us to increase our production and asset base. To date, we have funded acquisition transactions through a combination of cash, available borrowing capacity under our revolving credit facility and through the issuance of equity, including convertible Preferred Units.

Our current estimated capital spending for 2017 is approximately $13.0 million for the development, growth and maintenance of our oil and natural gas properties. We will consider adjustments to this capital program as business conditions and operating results warrant in concert with our evaluation of additional development opportunities that are identified throughout the year.

Revolving Credit Facility

At December 31, 2016, our borrowing base was $140.0 million and outstanding borrowings under our revolving credit facility were approximately $122.0 million. During the fall 2016 semi-annual redetermination of the revolving credit facility completed in October 2016, the lender group reaffirmed the existing conforming borrowing base of $140.0 million effective October 28, 2016. There were no changes to the terms or conditions of the credit agreement. See Note 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Commodity Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. At December 31, 2016, we had commodity derivative contracts covering approximately 75%, 43% and 12%, respectively, of our estimated 2017, 2018 and 2019 average daily production (estimate calculated based on the mid-point of our 2017 Boe production guidance as released on February 28, 2017 and multiplied by a 93% oil weighting based on fourth quarter 2016 reported production volumes). See Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Preferred Units

During August 2016, we issued $25.0 million of Preferred Units. Preferred unitholders receive quarterly distributions in cash at an annual rate of 8.0%, or, under certain circumstances, in additional Preferred Units rather than cash, at an annual rate of 10.0%. See Note 10 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2016 (in thousands). The contractual obligations we will actually pay in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

	2017	2018	2019	2020	2021	Total
Revolving credit facility [1]	$ —	$ 122,000	$ —	$ —	$ —	$ 122,000
Interest on long-term debt [2]	4,270	3,615	—	—	—	7,885
Deferred premiums for derivatives	5,048	401	—	—	—	5,449
Lease obligations	490	490	413	418	423	2,234
Preferred units [3]	2,000	2,000	2,000	2,000	1,222	9,222
Total	$ 11,808	$ 128,506	$ 2,413	$ 2,418	$ 1,645	$ 146,790

[1] For purposes of this table, we have assumed our revolving credit facility borrowings will not be paid until the maturity date on November 5, 2018.

[2] The interest obligation is based on our 3.5% borrowing rate in effect at December 31, 2016.

[3] Cash distributions are based on an annual rate of 8% assuming a redemption period on the fifth anniversary of the Preferred Units issuance. See Note 10 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Our ARO liability is not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our ARO liability at December 31, 2016, was approximately $11.3 million.

Off–Balance Sheet Arrangements

At December 31, 2016, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements

See Note 2 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information regarding recently issued accounting pronouncements.

ITEM 7A. 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. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

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

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

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

Our commodity price risk management activities are recorded at fair value and 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 derivative contracts at December 31, 2016, was a net liability of approximately $7.8 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 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Interest Rate Risk

Our exposure to changes in interest rates relates primarily to debt obligations. At December 31, 2016, we had debt outstanding of $122.0 million, with an annual effective interest rate of 3.92%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate would be approximately $0.5 million on an annual basis. At December 31, 2016, our revolving credit facility allowed for borrowings up to $140.0 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 8 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information.

Counterparty and Customer Credit Risk

We are subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current production. For the year ended December 31, 2016, sales of oil and natural gas to four purchasers accounted for 94% of our sales, and these purchasers accounted for 95% of our outstanding oil and natural gas accounts receivable. 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 December 31, 2016, our current purchasers had positive payment histories.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Mid-Con Energy Partners, LP

We have audited the accompanying consolidated balance sheets of Mid-Con Energy Partners, LP (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership’s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mid-Con Energy Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 28, 2017

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

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,359	$ 615
Accounts receivable:		
Oil and natural gas sales	5,302	4,551
Other	233	5,009
Derivative financial instruments	—	24,419
Prepaids and other	662	623
Total current assets	8,556	35,217
Property and Equipment:		
Oil and natural gas properties, successful efforts method:		
Proved properties	441,479	518,916
Other property and equipment	289	—
Accumulated depletion, depreciation, amortization and impairment	(176,551)	(232,008)
Total property and equipment, net	265,217	286,908
Derivative financial instruments	—	1,144
Other assets	2,513	3,817
Total assets	$ 276,286	$ 327,086
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 2,554	$ 3,185
Related parties	1,133	559
Derivative financial instruments	5,314	—
Accrued liabilities	146	165
Current maturities of long-term debt	—	30,000
Total current liabilities	9,147	33,909
Derivative financial instruments	2,495	—
Long-term debt	122,000	150,000
Other long-term liabilities	93	—
Asset retirement obligations	11,331	12,679
Commitments and contingencies		
Class A convertible preferred units - 11,627,906 and 0 issued and outstanding, respectively	19,570	—
EQUITY, per accompanying statements:		
Partnership equity:		
General partner interest	(248)	47
Limited partners - 29,912,230 and 29,724,890 units issued and outstanding, respectively	111,898	130,451
Total equity	111,650	130,498
Total liabilities, convertible preferred units and equity	$ 276,286	$ 327,086

See accompanying notes to consolidated financial statements

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

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil sales	$ 54,773	$ 72,520	$ 96,127
Natural gas sales	1,325	1,394	784
(Loss) gain on derivatives, net	(12,202)	22,366	29,361
Total revenues	43,896	96,280	126,272
Operating costs and expenses:			
Lease operating expenses	22,692	33,591	26,091
Oil and natural gas production taxes	2,893	3,487	6,325
Impairment of proved oil and natural gas properties	895	103,938	30,206
Impairment of proved oil and natural gas properties sold	3,578	—	—
Depreciation, depletion and amortization	23,074	34,174	21,877
Accretion of discount on asset retirement obligations	577	432	250
General and administrative	6,890	9,411	14,313
Total operating costs and expenses	60,599	185,033	99,062
Loss on sales of oil and natural gas properties, net	(560)	—	—
(Loss) income from operations	(17,263)	(88,753)	27,210
Other (expense) income:			
Interest income	12	11	13
Interest expense	(7,487)	(7,258)	(4,731)
Other (expense) income	(76)	547	—
Loss on settlement of ARO	—	(42)	—
Total other expense	(7,551)	(6,742)	(4,718)
Net (loss) income	(24,814)	(95,495)	22,492
Less: Distributions to preferred unitholders	1,249	—	—
Less: General partner's interest in net (loss) income	(295)	(1,146)	354
Limited partners' interest in net (loss) income	$ (25,768)	$ (94,349)	$ 22,138
Net (loss) income per limited partner unit:			
Basic	$ (0.86)	$ (3.18)	$ 0.98
Diluted	$ (0.86)	$ (3.18)	$ 0.98
Weighted average limited partner units outstanding:			
Limited partner units (basic)	29,834	29,642	22,499
Limited partner units (diluted)	29,834	29,642	22,518

See accompanying notes to consolidated financial statements

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

	Year Ended December 31,		
	2016	**2015**	**2014**
Cash Flows from Operating Activities:			
Net (loss) income	$ (24,814)	$ (95,495)	$ 22,492
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	23,074	34,174	21,877
Debt issuance costs amortization	1,372	1,156	348
Accretion of discount on asset retirement obligations	577	432	250
Impairment of proved oil and natural gas properties	895	103,938	30,206
Impairment of proved oil and natural gas properties sold	3,578	—	—
Loss on settlement of ARO	—	42	—
Cash paid for settlements of ARO	—	(82)	—
Mark to market on derivatives:			
Loss (gain) on derivatives, net	12,202	(22,366)	(29,361)
Cash settlements received for matured derivatives	20,511	28,543	891
Cash settlements received for early terminations and modifications of derivatives, net	5,820	11,069	—
Cash premiums paid for derivatives, net	(5,161)	(15,765)	—
Loss on sales of oil and natural gas properties, net	560	—	—
Non-cash equity-based compensation	1,184	3,204	7,394
Changes in operating assets and liabilities:			
Accounts receivable	(751)	3,500	(1,273)
Other receivables	4,935	(566)	(3,966)
Prepaids and other	(39)	29	(461)
Accounts payable and accrued liabilities	(7)	(3,388)	2,067
Net cash provided by operating activities	43,936	48,425	50,464
Cash Flows from Investing Activities:			
Additions to oil and natural gas properties	(7,223)	(13,893)	(33,969)
Additions to other property and equipment	(165)	—	—
Acquisitions of oil and natural gas properties	(18,722)	(1)	(155,354)
Proceeds from sales of oil and natural gas properties	17,635	—	—
Net cash used in investing activities	(8,475)	(13,894)	(189,323)
Cash Flows from Financing Activities:			
Proceeds from line of credit	—	28,000	168,000
Payments on line of credit	(58,000)	(53,000)	(75,000)
Issuance of common units	—	—	96,010
Offering costs	(16)	(194)	—
Distributions to common units	—	(11,266)	(44,564)
Debt issuance costs	(68)	(688)	(3,789)
Proceeds from sale of convertible preferred units, net of offering costs	24,646	—	—
Distributions to preferred units	(279)	—	—
Net cash (used in) provided by financing activities	(33,717)	(37,148)	140,657
Net increase (decrease) in cash and cash equivalents	1,744	(2,617)	1,798
Beginning cash and cash equivalents	615	3,232	1,434
Ending cash and cash equivalents	$ 2,359	$ 615	$ 3,232

See accompanying notes to consolidated financial statements

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

	General Partner	Limited Partner Units	Limited Partner Amount	Total Equity
Balance, December 31, 2013	$ 1,716	19,319	$ 65,072	$ 66,788
Equity-based compensation	—	332	7,415	7,415
Issuance of limited partner units - acquisitions	—	3,715	86,001	86,001
Issuance of limited partner units, net of offering costs	—	5,800	96,010	96,010
Distributions to common units	(742)	—	(43,822)	(44,564)
Net income	354	—	22,138	22,492
Balance, December 31, 2014	1,328	29,166	232,814	234,142
Equity-based compensation	—	559	3,311	3,311
Offering costs	—	—	(194)	(194)
Distributions to common units	(135)	—	(11,131)	(11,266)
Net loss	(1,146)	—	(94,349)	(95,495)
Balance, December 31, 2015	47	29,725	130,451	130,498
Equity-based compensation	—	187	1,184	1,184
Offering costs	—	—	(16)	(16)
Distributions to preferred units	—	—	(779)	(779)
Allocation of value to beneficial conversion feature of Class A convertible preferred units	—	—	6,047	6,047
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(470)	(470)
Net loss	(295)		(24,519)	$ (24,814)
Balance, December 31, 2016	$ (248)	29,912	$ 111,898	$ 111,650

See accompanying notes to consolidated financial statements

Note 1. Organization and Nature of Operations

Nature of Operations

Mid-Con Energy Partners, LP is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on EOR. Our limited partner units ("common units") are listed on the NASDAQ Global Select Market under the symbol "MCEP." Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.

Reclassifications

The consolidated statements of operations for previous periods include certain reclassifications to the other income (expense) accounts that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss).

Non-cash Investing, Financing and Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Non-cash investing and financing information:			
Change in oil and natural gas properties - accrued capital expenditures	$ (259)	$ (560)	$ 351
Tenant improvement allowance deferred - other property and equipment	$ 124	$ —	$ —
Cash paid for interest	$ 6,198	$ 6,070	$ 4,600
Common units issued - acquisition of oil properties	$ —	$ —	$ 86,001

Note 2. Summary of Significant Accounting Policies

Basis of presentation and principles of consolidation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2016 and 2015. These financial statements also include the results of our operations, cash flows and changes in equity for the years ended December 31, 2016, 2015 and 2014.

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our subsidiary is Mid-Con Energy Properties. All intercompany transactions and account balances have been eliminated.

We aggregate all of our oil and natural gas properties into one business segment engaged in the exploitation, development and production of oil and natural gas properties.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. Depletion and impairment of oil and natural gas properties, in part, are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, ARO, fair value of assets acquired and liabilities assumed in business combinations and fair value of derivative financial instruments.

Cash and cash equivalents

We consider all cash on hand, depository accounts held by banks and money market accounts with an original maturity of three months or less to be cash equivalents.

Accounts receivable

Accounts receivable are generated from the sale of oil and natural gas to various customers. We routinely assess the financial strength of our customers and bad debts are recorded based on an account level review after all means of collection have been exhausted, and the potential recovery is considered remote. At December 31, 2016 and 2015, we did not have any reserves for doubtful accounts and we did not incur any expenses related to bad debts in any period presented.

Revenue recognition

We follow the sales method of accounting for oil and natural gas revenues. Under this method, revenues are recognized based on our share of actual proceeds from oil and natural gas sold to purchasers. Natural gas revenues would not have been significantly altered for the period presented had the entitlements method of recognizing natural gas revenues been utilized. If reserves are not sufficient to recover natural gas overtake positions, a liability is recorded. We had no significant natural gas imbalances at December 31, 2016 or 2015. We do not extract NGLs from our natural gas production prior to the sale and transfer of title of the natural gas stream to our purchasers. While some of our purchasers extract NGLs from the natural gas stream sold by us to them, we have no ownership in such NGLs. Therefore we do not report NGLs in our production or proved reserves.

Oil and natural gas properties

Our oil and natural gas exploitation and production activities are accounted for using the successful efforts method. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized costs relating to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. The depreciation of capitalized production equipment is based on the units-of-production method using proved developed reserves on a field basis.

Capitalized costs of individual properties abandoned or retired are charged to accumulated depletion, depreciation and amortization. Proceeds from sales of individual properties are credited to property costs. No gain or loss is recognized until the entire amortization base (field) is sold or abandoned.

Costs of significant non-producing properties and wells in the process of being drilled are excluded from depletion until such time as the proved reserves are established or impairment is determined. Costs of significant development projects are excluded from depletion until the related project is completed. We had no significant costs excluded from depreciation during any of the periods presented. We capitalize interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. We had no capitalized interest during any of the periods presented.

We review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves and risk-adjusted probable and possible 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. We review our oil and natural gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base. These evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. Cash flow estimates for the impairment testing excludes derivative instruments used to mitigate the price risk related to lower future oil and natural gas prices.

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 ARO are primarily associated with plugging and abandoning wells. We typically incur this liability upon acquiring or drilling a well. 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 ARO on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. Over time, the liability is accreted each period toward its future value and the capitalized cost is depleted as a component of development costs. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability. See Note 7 for additional information.

Derivatives and hedging

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 derivatives (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders.

Derivatives are recorded at fair value and are presented on a net basis on the consolidated balance sheets as assets or liabilities. The Partnership nets the fair value of derivatives by counterparty where the right of offset exists and determines the fair value of its derivatives by utilizing certain pricing models to validate the data provided by third parties. See Note 6 Fair Value Disclosures for more information.

We do not designate derivatives as hedges for accounting purposes; therefore, the mark-to-market adjustment reflecting the change in the fair value of unsettled derivative contracts is recorded in current period earnings. When prices for oil are volatile, a significant portion of the effect of our hedging activities consists of non-cash income or expenses 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 5 for discussion regarding Derivative Financial Instruments.

Equity-based compensation

The cost of employee services received in exchange for equity instruments is measured based on the grant-date fair value and is recorded as compensation expense over the requisite service period (often the vesting period). Awards subject to performance criteria vest when it is probable that the performance criteria will be met. Compensation expense for awards is recorded upon vesting, based on their grant-date fair value, net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. No compensation expense is recognized for equity instruments that do not vest.

Debt issuance costs

Debt placement costs are stated at cost, net of amortization, which is computed using the straight-line method and recognized as interest expense in the consolidated statements of operations over the remaining life of the agreement. Since our debt consists of a revolving credit facility, net debt placement costs are presented in "Other Assets" in our consolidated balance sheets. When debt is retired before its scheduled maturity date, we write off any remaining issuance costs associated with that debt.

Income taxes

We are a partnership that is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, our taxable income or loss is includable in the federal income tax returns of our unitholders. Earnings or losses for financial statement purposes may differ significantly from those reported to the individual unitholders for income tax purposes as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

Allocation of Net Income (Loss)

Net income (loss), net of distributions on the Preferred Units and amortization of the preferred unit beneficial conversion feature, is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership during the period. The allocation of net income (loss) is presented in our consolidated statements of operations. Diluted net income (loss) per partner unit reflects the potential dilution of non-vested restricted stock awards. For the years ended December 31, 2016, and 2015, this potentially dilutive item was anti-dilutive due to the Partnership's net loss and, therefore, was excluded from the calculation of diluted net income (loss) per partner unit.

Recently Issued 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. We plan to adopt ASU 2014-09 effective January 1, 2018, using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018, as an adjustment to opening retained earnings. We do not expect our revenue recognition under the new guidance to materially differ from our current revenue recognition practice. We do not expect the cumulative effect adjustment to opening retained earnings to be significant.

In February 2016, the FASB issued ASU No. 2016-02, " *Leases* (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018 and early adoption is permitted. As of December 31, 2016, the Partnership has not elected early adoption. We believe the primary impact of adopting this standard will be the recognition of assets and liabilities on our balance sheet for current operating leases. We are still evaluating the impact of this standard.

In 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. As of December 31, 2016, the Partnership has not elected early adoption. Based on our initial evaluation, we do not anticipate a material impact to our consolidated financial statements upon adoption of this standard.

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

Note 3. Acquisitions and Divestitures

Permian Bolt-On Acquisition

On August 11, 2016, we acquired multiple oil and natural gas properties located in Nolan County, Texas for cash consideration of approximately $18.7 million , after estimated post-closing purchase price adjustments. The Permian Bolt-On acquisition was accounted for under the acquisition method of accounting. The assets acquired and liabilities assumed in the acquisition were recorded in our consolidated balance sheets at their estimated fair values as of the acquisition date using assumptions that represent Level 3 fair value measurement inputs. The estimated fair values as of the acquisition date were based on a reserve report prepared by our reservoir engineering staff and audited by CG&A. See Note 6 in this section for additional discussion of our fair value measurements. The results of operations of the acquired properties have been included in our consolidated financial statements since the acquisition closed on August 11, 2016. The consolidated statement of operations for the year ended December 31, 2016, includes revenues of approximately $2.7 million and lease operating expenses of approximately $0.6 million . The transaction was funded by a private offering of $25.0 million Preferred Units. See Note 10 in this section for additional information regarding the issuance of Preferred Units. The recognized fair values of the assets acquired and liabilities assumed are as follows (in thousands):

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

Hugoton Core Area Divestiture

On July 28, 2016, we sold our properties located in our Hugoton core area for cash proceeds of approximately $17.6 million , including post-closing adjustments. We recognized a loss of approximately $0.6 million which is included as "Loss on sales of oil and natural gas properties, net" in our consolidated statements of operations. Additionally, we recorded impairment of proved oil and natural gas properties of approximately $3.6 million of that was recorded when these properties were originally reported as held for sale.

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

	Year Ended December 31,					
	2016		2015		2014	
	(in thousands)					
Oil and natural gas sales	$	3,602	$	11,744	$	23,708
Expenses [(1)]	$	7,717	$	51,505	$	43,384

[(1)] Expenses include lease operating expenses, production taxes, accretion, depletion and impairment expenses.

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

Note 4. 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 and ME3 Oilfield Service, who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, unrestricted units, restricted units, phantom units, distribution equivalent rights granted with phantom units and other types of awards. The Long-Term Incentive Program is administered by the controlling members of our general partner, Charles R. Olmstead, Executive Chairman of the Board, and Jeffrey R. Olmstead, Chief Executive Officer, and approved by the Board of Directors of the general partner. If an employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding.

On November 20, 2015, the Board of Directors of the general partner recommended, and the common unitholders 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 . The following table shows the number of existing awards and awards available under the Long-Term Incentive Program at December 31, 2016:

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,187,306)
Restricted units granted, net of forfeitures	(400,424)
Equity-settled phantom units granted, net of forfeitures	(457,500)
Awards available for future grant	1,468,770

We recognized approximately $1.2 million , $3.2 million and $7.7 million of total equity-based compensation expense for the years ended December 31, 2016, 2015 and 2014, respectively. These costs are reported as a component of general and administrative expense in our consolidated statements of operations.

Unrestricted unit awards

We account for unrestricted awards as equity awards since they are settled by issuing common units. During the year ended December 31, 2016, we granted 73,932 unrestricted units with an average grant date fair value of $1.20 per unit. During the year ended December 31, 2015, we granted 274,550 unrestricted units with an average grant date fair value of $4.85 per unit.

Restricted unit 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 units is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. We did not issue any restricted units during the year ended December 31, 2016. During the year ended December 31, 2015, we granted 268,000 restricted units with one-third vesting immediately and the other two-thirds vesting over two years, and 26,100 restricted units with a three - year vesting period. As of December 31, 2016, there were approximately $0.1 million of unrecognized compensation costs related to non-vested restricted units. These costs are expected to be recognized over a weighted average period of approximately eight months .

A summary of our restricted unit awards for the years ended December 31, 2016, and 2015 is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	109,800	$ 23.28
Units granted	294,100	5.04
Units vested	(148,195)	12.43
Units forfeited	(32,872)	9.28
Outstanding at December 31, 2015	222,833	$ 8.49
Units granted	—	—
Units vested	(112,478)	9.16
Units forfeited	(33,433)	9.69
Outstanding at December 31, 2016	76,922	$ 5.67

Equity-settled phantom unit awards

We account for equity-settled phantom awards as equity awards since they 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 the 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 year ended December 31, 2016, we granted 347,500 equity-settled phantom awards with one-third vesting immediately and the other two-thirds vesting over two years and 27,000 equity-settled phantom awards with a three -year vesting period. During the year ended December 31, 2015, we granted 69,000 equity-settled phantom units with one-third vesting immediately and the other two-thirds vesting over two years and 46,500 equity-settled phantom units with a three -year vesting period. As of December 31, 2016, there were approximately $0.3 million of unrecognized compensation costs related to equity-settled phantom units. These costs are expected to be recognized over a weighted average period of approximately one year, six months .

A summary of our equity-settled phantom unit awards for the years ended December 31, 2016, and 2015 is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2014	—	$ —
Units granted	115,500	2.87
Units vested	(23,000)	3.12
Units forfeited	(15,000)	2.81
Outstanding at December 31, 2015	77,500	2.81
Units granted	374,500	1.55
Units vested	(146,841)	2.03
Units forfeited	(17,500)	2.02
Outstanding at December 31, 2016	287,659	$ 1.64

Note 5. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices and specific delivery points. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent to do so, or as required by our lenders. These contracts are presented as derivative financial instruments on our consolidated financial statements. We account for our commodity derivative contracts at fair value. See Note 6 in this section for a description of our fair value measurements.

At December 31, 2016, our commodity derivative contracts were in a net liability position with a fair value of approximately $7.8 million and at December 31, 2015, a net asset position with a fair value of approximately $25.6 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 commodity derivative contracts under lower commodity prices and we could incur a loss. During the three years ended December 31, 2016, all of our counterparties have performed pursuant to their commodity derivative contracts.

At December 31, 2016, and 2015, our commodity derivative contracts had maturities at various dates through December 2019 and December 2017, respectively, and were comprised of commodity price swaps, call, put and collar 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 commodity 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 commodity at maturity less 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 commodity 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.

For commodity price collar contracts, a collar is the combination of a put purchased or sold by a party and a call option sold or purchased by the same party. The collar is defined as costless when the value of the option purchased is approximately offset by the value of the option sold.

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

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

Period Covered	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Collars - 2017	$ 43.75	$ 50.68	658	WTI
Puts - 2017	$ 50.00	$ —	1,932	WTI
Collars - 2018	$ 44.38	$ 55.52	1,315	WTI
Puts - 2018	$ 45.00	$ —	164	WTI
Collars - 2019	$ 50.00	$ 60.52	427	WTI

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

	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 extended 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 and enhance the contracts through September 2016. The restructuring also resulted in approximately $4.1 million of deferred premium put options which have been paid as of December 31, 2016.

In connection with the fall 2015 semi-annual redetermination of our borrowing base, we entered into additional 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 Producing reserves. No cash settlements were required and the contracts included deferred premiums of approximately $7.8 million that will be paid through December 2017. As of

December 31, 2016, we had paid approximately $2.9 million of the deferred premiums in connection with these contract settlements.

In connection with the spring 2016 semi-annual redetermination of our borrowing base, we unwound and early terminated existing hedges covering production from July 2016 through September 2016 and entered into new commodity derivative contracts which extend through June 2018. In connection with the early termination of our commodity derivative contracts, we received proceeds of approximately $5.8 million and paid related deferred premiums of approximately $1.5 million.

In connection with the non-scheduled redetermination of our borrowing base and Amendment No.10 to our credit agreement executed in August 2016, we entered into new commodity derivative contracts covering at least 75% of our 2017 projected monthly production and at least 50% of our 2018 projected monthly production, calculated based on Proved Developed Producing reserves. The new contracts extend through December 2018. No cash settlements were required and the contracts included deferred premiums of approximately $0.4 million that will be paid July 2018 through December 2018.

During the fourth quarter of 2016, we entered into commodity derivative contracts covering production from April 2017 through December 2019. In connection with the new commodity derivative contracts, we paid approximately $0.1 million in premiums at inception and deferred approximately $0.1 million of premiums that will be paid from April 2017 through December 2017.

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

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

	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the 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 consolidated statements of operations:

	Year Ended December 31,		
	2016	2015	2014
		(in thousands)	
Net settlements on matured derivatives (1)	$ 20,511	$ 28,543	$ 891
Net settlements on early terminations and modifications of derivatives (1)	5,820	11,069	—
Net change in fair value of derivatives	(38,533)	(17,246)	28,470
Total (loss) gain on derivatives, net	$ (12,202)	$ 22,366	$ 29,361

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

Note 6. Fair Value Disclosures

Fair Value of Financial Instruments

The carrying amounts reported in our consolidated balance sheets for cash, accounts receivable and accounts payable approximate their fair values. The carrying amount of debt under our revolving credit facility approximates fair value because the revolving credit facility's variable interest rate resets frequently and approximates current market rates available to us. We account for our commodity derivative contracts at fair value as discussed in "Assets and Liabilities Measures at Fair Value on a Recurring Basis" below.

Fair Value Measurements

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

Level 1 —Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. We consider active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an on-going basis.

Level 2 —Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability. Level 2 instruments primarily include swap, call, put and collar contracts.

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

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

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation approach or related inputs for the years ended December 31, 2016, and 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 utilizing certain pricing models. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. The Partnership's deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as the Partnership utilizes a net present value calculation to determine the valuation. See Note 5 in this section for a summary of our derivative financial instruments.

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

ARO

We estimate the fair value of 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 7 in this section for a summary of changes in ARO.

Acquisitions

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

Reserves

We calculate the estimated fair values of reserves and properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (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. See Note 16 in this section for additional information regarding our oil and natural gas reserves.

Impairment

The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the 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. For the years ended December 31, 2016, and 2015, we recorded non-cash impairment of approximately $0.9 million and $103.9 million , respectively. The 2016 non-cash impairment resulted from a revision of reserve estimates for a property in our Permian core area. The non-cash impairment in 2015 resulted from a decline in commodity prices and to a lesser degree, reduced reserve estimates. These non-cash transactions are included in "Impairment of proved oil and natural gas properties" in our consolidated statements of operations. During the year ended December 31, 2016, we recorded non-cash impairment of approximately $3.6 million related to the Hugoton core area divestiture to reduce the carrying amount of those assets to their fair value. These assets and liabilities were deemed to meet held-for-sale accounting criteria as of June 30, 2016, accordingly, the impairment is included in "Impairment of proved oil and natural gas properties sold" in our consolidated statements of operations.

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

	Level 1	Level 2	Level 3	Fair Value
	(in thousands)			
December 31, 2016				
Assets and Liabilities Measured at Fair Value on a Recurring Basis				
Derivative financial instruments - asset	$ —	$ 1,976	$ —	$ 1,976
Derivative financial instruments - liability	$ —	$ 4,336	$ —	$ 4,336
Derivative deferred premiums - liability	$ —	$ —	$ 5,449	$ 5,449
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

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

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Balance of Level 3 at beginning of period	$ (9,973)	$ —
Derivative deferred premiums - purchases	(516)	(11,914)
Derivative deferred premiums - settlements	5,040	1,941
Balance of Level 3 at end of period	$ (5,449)	$ (9,973)

Note 7. 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 ARO 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 removal and future restoration obligation requires management to make estimates and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future ARO on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. 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.

For the years ended December 31, 2016, and 2015, our ARO were reported as "Asset retirement obligations" in our consolidated balance sheets. Changes in our ARO for the periods indicated are presented in the following table:

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Asset retirement obligations - beginning of period	$ 12,679	$ 7,363
Liabilities incurred for new wells and interest	747	42
Liabilities settled upon plugging and abandoning wells	—	(40)
Liabilities removed upon sale of wells	(2,827)	—
Revision of estimates	155	4,882
Accretion expense	577	432
Asset retirement obligations - end of period	$ 11,331	$ 12,679

Note 8. Debt

A summary of our debt for the years ended December 31, 2016, and 2015 is presented below:

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Revolving credit facility (matures November 2018)	$ 122,000	$ 180,000
Less: current portion	—	30,000
Total long-term debt	$ 122,000	$ 150,000

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 the spring and fall of each year with an additional redetermination, either at our request or at the request of the lenders, during the period between each scheduled borrowing base redetermination. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election: (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 year ended December 31, 2016, the average effective rate was approximately 3.92% . Any unused portion of the borrowing base will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders. The revolving credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, 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 year ended December 31, 2016.

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 spring 2015 semi-annual redetermination and amendment to the credit agreement completed 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 the fall 2015 semi-annual redetermination and amendment to the credit agreement completed in November 2015, the borrowing base under the underlying revolving credit facility was reduced to \$190.0 million from \$220.0 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 revolving credit facility amendment also designated Wells Fargo Bank, National Association, as our administrative and collateral agent, replacing Royal Bank of Canada. This amendment 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 at the time of the agreement. 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 as "interest expense" in our consolidated statements of operations.

During the spring 2016 semi-annual redetermination and amendment to the credit agreement completed in May 2016, the effective borrowing base as of June 1, 2016 was reduced to \$163.0 million and was comprised of a \$110.0 million conforming tranche and a permitted overadvance of \$53.0 million . The permitted overadvance was scheduled to mature on November 1, 2016. In addition, the amendment (i) required the Partnership to provide a monthly excess cash flow report; (ii) required the Partnership to make varied minimum monthly principal payments totaling approximately \$1.9 million through October 31, 2016; (iii) reduced the conforming borrowing base to \$105.0 million upon the close of the Hugoton core area divestiture; (iv) allowed an additional non-scheduled borrowing base redetermination between September 1, 2016 and November 1, 2016 to be requested by any lenders; (v) increased the minimum collateral coverage from 90% to 95% of proved reserves (and 100% of Proved Developed Producing reserves); (vi) required the Partnership to unwind and early terminate existing hedges covering production from July 2016 through September 2016 and add new at-the-market swap contracts to replace these hedge terminations; and (vii) required the net proceeds from the Hugoton core area divestiture and from the early termination of hedge contracts to be applied to debt reduction.

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

During the fall 2016 semi-annual borrowing base redetermination of our revolving credit facility completed in October 2016, the lender group reaffirmed the existing conforming borrowing base of \$140.0 million effective October 28, 2016. There were no changes to the terms or conditions of the credit agreement. The next regularly scheduled borrowing base redetermination will occur on or about April 30, 2017.

Note 9. Commitment and Contingencies

Leases

We lease corporate office space in Tulsa, Oklahoma, and Abilene, Texas. We were also allocated office rent from Mid-Con Energy Operating through August 2016 for office space in Dallas, Texas. For the years ended December 31, 2016, 2015 and 2014, total lease expenses were approximately \$0.4 million , \$0.4 million , and \$0.3 million , respectively. These expenses are included in general and administrative expenses in our consolidated statements of operations.

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

2017	$	490
2018		490
2019		413
2020		418
2021		423
Total	$	2,234

Services Agreement

We are party to a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides certain services to us including management, administrative and operational services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. See Note 11 in this section for additional information.

Employment Agreements

Our general partner has entered into employment agreements with Charles R. Olmstead, Executive Chairman of the Board and Jeffrey R. Olmstead, President and Chief Executive Officer. The employment agreements automatically renew for one-year terms unless either we or the employee gives written notice of termination by at least February1st 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 them. The agreement stipulates that if there is a change of control, termination of employment, with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $0.4 million to $0.8 million , including the value of vesting of any outstanding units.

Legal

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

Note 10. Equity

Common Units

At December 31, 2016, and 2015, the Partnership's equity consisted of 29,912,230 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 to sell, from time to time through or to the Managers (as defined in the agreement), up to $50.0 million in common units representing limited partner interests. In connection with the Preferred Units agreement described below, the Partnership suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date until the fifth anniversary of the closing date of the Preferred Units purchase agreement, without the consent of a majority of the holders of the outstanding Preferred Units.

Preferred Units

On August 11, 2016, we completed a private placement of 11,627,906 Preferred Units for an aggregate offering price of $25.0 million . The Preferred Units were issued at a price of $2.15 per Preferred Unit (the "Unit Purchase Price"). Proceeds from this issuance were used to fund the Permian Bolt-On acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility.

We pay holders of the Preferred Units a cumulative, quarterly distribution on all Preferred Units then outstanding (i) in cash at an annual rate of 8.0% , or (ii) in the event that the Partnership's existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Preferred Units), at an annual rate of 10.0% . Such distributions will be paid for each such quarter within 45 days after such quarter end.

At any time after the six-month anniversary and prior to the five year anniversary of the closing date, each holder of the Preferred Units shall have the right, subject to certain conditions, to convert all or a portion of their Preferred Units into common units representing limited partner interests in the Partnership on a one-for-one basis, subject to adjustment for splits, subdivisions, combinations and reclassifications of the common units; provided that any holder electing conversion requests the conversion of at least the lesser of (i) 100% of such holder's remaining Preferred Units or (ii) $1.0 million of Preferred Units, based on the Unit Purchase Price. At any time after the fifth anniversary of the closing date of the offering, each holder shall have the right to cause the Partnership to redeem all or any portion of their Preferred Units for cash at the Unit Purchase Price, and any remaining Preferred Units will thereafter be converted to common units on a one-for-one basis, subject to adjustment for splits, reverse splits, subdivisions, combinations and reclassifications of the common units. Upon conversion of Preferred Units, the Partnership will pay any distributions (to the extent accrued and unpaid as of the then most recent Preferred Units distribution date) on the converted units in cash.

Upon a change of control, each holder will have the right, at its election, to either (i) if the Partnership is the surviving entity of such change of control, continue to hold Preferred Units; or (ii) convert all or any portion of the Preferred Units held by such holder into common units on a one-for-one basis, subject to adjustments for splits, reverse splits, subdivisions, combinations and reclassifications. If any Preferred Units remain outstanding following a change of control in which the Partnership is not the surviving entity, then immediately following effectiveness of such change of control, the Partnership shall redeem in cash all, but not less than all, of the outstanding Preferred Units at a price per Preferred Unit equal to the Unit Purchase Price multiplied by the change of control redemption multiple then in effect.

Under the registration rights agreements, we were required to use reasonable best efforts to file, within 90 days of the closing date, a registration statement registering resales of common units issued or to be issued upon conversion of the Preferred Units and have the registration statement declared effective within 180 days after the closing date. The common units to be issued are pending effectiveness of registration under a previously filed shelf registration statement on Form S-3. We are required to use reasonable best efforts to continue to maintain the effectiveness of the registration statement until all securities have been sold or the third anniversary of the effectiveness deadline. In addition, from and after the first anniversary of the closing date, holders of an aggregate of at least $1.0 million of Preferred Units (based on the Unit Purchase Price) shall have piggyback registration rights on all Partnership registrations, subject to customary carve backs, and holders of an aggregate of at least $5.0 million of Preferred Units (based on the Unit Purchase Price) shall have demand registration rights; provided that the holders shall be entitled to a demand registration right not more frequently that once during any twelve month period.

In the event of any liquidation, dissolution or winding-up of the Partnership, each preferred unit will receive in preference to the holders of all existing classes or series of equity securities of the Partnership a per unit amount equal to the Unit Purchase Price (subject to any customary anti-dilution adjustments), plus all accrued and unpaid distributions on such Preferred Units (the "liquidation preference").

The Preferred Unit purchase agreement also required the Partnership to suspend sales of common units pursuant to the Equity Distribution Agreement from the closing date through the fifth anniversary of the closing date and prohibits the Partnership from incurring any indebtedness (other than under the Partnership's existing revolving credit facility and trade accounts payable arising in the ordinary course of business) without the consent of the majority of the holders of the Preferred Units.

We received net proceeds of approximately $24.6 million (net of issuance costs of approximately $0.4 million) in connection with the issuance of Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Preferred Units (approximately $18.6 million) and the beneficial conversion feature (approximately $6.0 million). A beneficial conversion feature is defined as a non-detachable conversion feature that is in the money at the commitment date. Per accounting guidance, we are required to allocate a portion of the proceeds from the Preferred Units to the beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per-share value of our common units at the issuance date) and the proceeds attributed to the Preferred Units. We will record the accretion attributed to the beneficial conversion feature as a deemed distribution using the straight line method over the five year period prior to the effective date of the holders conversion right. Accretion of the beneficial conversion feature was approximately $0.5 million for the year ended December 31, 2016.

Our 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 of future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors.

As of December 31, 2016, cash distributions to our common units continue to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions and also prohibits us from making common unit cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution. Management and the Board of Directors will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. The following table summarizes cash distributions paid to our common units for the year ended December 31, 2015:

Date Paid	**Period Covered**	**Distribution per Unit**	**Total Distributions (in thousands)**
February 13, 2015	October 1, 2014 - December 31, 2014	$ 0.125	$ 3,752
May 14, 2015	January 1, 2015 - March 31, 2015	$ 0.125	3,752
August 13, 2015	April 1, 2015 - June 30, 2015	$ 0.125	3,762
			$ 11,266

The holders of the Preferred Units are entitled to certain rights that are senior to the rights of holders of common units, such as rights to distributions and rights upon liquidation of the Partnership. Preferred unitholders receive quarterly distributions in cash at an annual rate of 8.0% or, under certain circumstances, in additional Preferred Units, rather than cash, at an annual rate of 10.0% . As of December 31, 2016, all Preferred Unit distributions have been paid in cash. No payment or distribution on common units for any quarter is permitted prior to the payment in full of the Preferred Units distribution (including any outstanding arrearages). At December 31, 2016, the Partnership had accrued approximately $0.5 million for the fourth quarter 2016 dividends that are to be paid in February 2017. The following table summarizes cash distributions paid on our Preferred Units for the year ended December 31, 2016:

Date Paid	**Period Covered**	**Distribution per Unit**	**Total Distributions (in thousands)**
November 14, 2016	August 11, 2016 - September 30, 2016	$ 0.024	$ 279

Allocations of Net Income (Loss)

Net income (loss), net of distributions on the Preferred Units and amortization of the preferred unit beneficial conversion feature (see Preferred Units section), is allocated between our general partner and the limited partner unitholders in proportion to their pro rata ownership (exclusive of the Preferred Units limited partnership interest) during the period. The allocation of net income (loss) is presented in our consolidated statements of operations. Diluted net income (loss) per partner unit reflects the potential dilution of non-vested restricted stock awards. For the years ended December 31, 2016, and 2015, this potentially dilutive item was anti-dilutive due to the Partnership's net loss and, therefore, was excluded from the calculation of diluted net income (loss) per partner unit.

Note 11. Related Party Transactions

Agreements with Affiliates

The following agreements were negotiated among affiliated parties and, consequently, are not the result of arm's length negotiations. The following is a description of those agreements that have been entered into with the affiliates of our general partner and with our general partner.

Services Agreement

We are party to a services agreement with our affiliate, Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating provides certain services to us, including management, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. These expenses are included in general and administrative expenses in our consolidated statements of operations.

Operating Agreements

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

Oilfield Services

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

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

	Year Ended December 31,		
	2016	**2015**	**2014**
Amounts paid for:	(in thousands)		
Services agreement	$ 3,403	$ 3,654	$ 3,775
Operating agreements	6,221	8,332	6,120
Oilfield services	3,058	3,653	3,749
	$ 12,682	$ 15,639	$ 13,644

At December 31, 2016, we had payables to our affiliate, Mid-Con Energy Operating, of approximately $1.1 million , comprised of a joint interest billing payable of approximately $0.5 million and a payable for operating services of approximately $0.6 million . At December 31, 2015, we had payables to our affiliate Mid-Con Energy Operating of approximately $0.5 million , comprised of a joint interest billing payable of approximately $0.1 million and a payable for operating services of approximately $0.4 million . These amounts were included in accounts payable-related parties in our consolidated balance sheets.

Note 12. Credit Risk

Credit risk relates to the risk of loss resulting from non-performance of non-payment by counterparties under the terms of their contractual obligations, thereby impacting the amount and timing of expected cash flows. Financial instruments which potentially subject us to credit risk consist principally of cash balances, accounts receivable and derivative financial instruments. We maintain cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. We have not experienced any significant losses from such investments.

For the year ended December 31, 2016, sales of oil and natural gas to four purchasers accounted for 94% of our sales. At December 31, 2016, these purchasers accounted for 95% of our outstanding oil and natural gas accounts receivable. For the year ended December 31, 2015, sales of oil and natural gas to three purchasers accounted for 75% of our sales and at December 31, 2015, accounted for 73% of our oil and natural gas receivables. For the year ended December 31, 2014, we had three purchasers that accounted for 74% of our sales and at December 31, 2014, accounted for 45% of our oil and natural gas receivables. We believe that the loss of any one purchaser would not have a material adverse effect on our ability to sell our oil and natural gas production as other purchasers would be accessible. We have not experienced any significant losses due to uncollectible accounts receivable from these purchasers.

Note 13. Employee Benefit Plans

In 2011, our general partner adopted the Mid-Con Energy Partners, LP Long-Term Incentive Program which is intended to promote the interests of the partnership by providing to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating and ME3 Oilfield Service, grants of restricted units, phantom units, unit appreciation rights, distribution equivalent rights and other unit based awards to encourage superior performance. The Long-Term Incentive Program is also intended to enhance the ability of the general partner and our affiliates, to attract and retain the services of individuals who are essential for the growth and profitability of the partnership and to encourage them to devote their best efforts to advancing the business of the partnership.

The Long-Term Incentive Program is administered by Charles R. Olmstead and Jeffrey R. Olmstead, the controlling members of our general partner, and approved by the Board of Directors of the general partner. Except as set forth in the employment agreements of the executive officers of our general partner, there is no set formula for granting awards to our employees, officers, consultants and directors of our general partner and our affiliates. In determining whether to grant awards and the amount of any awards, the administrators take into consideration discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package. See Note 4 in this section for additional information regarding awards granted under the Long-Term Incentive Program.

Note 14. Income Taxes

We do not pay federal income taxes, as our profits or losses are reported to the taxing authorities by our individual partners.

Note 15. Subsequent Events

Distributions

The Board of Directors of the general partner declared a Preferred Unit cash distribution for the fourth quarter of 2016, according to terms outlined in the Partnership Agreement. A cash distribution of $0.043 per Preferred Unit, or approximately $0.5 million in aggregate, was paid on February 14, 2017 to holders of record as of the close of business on February 7, 2017.

Appointment and Departure of Certain Officers

Mr. S. Craig George resigned from the Board of Directors of the general partner effective January 31, 2017.

Mr. Wilkie S. Colyer Jr. was appointed to the Board of Directors of the general partner effective February 1, 2017.

Equity Awards

On February 22, 2017, the Board of Directors of our general partner authorized the issuance of 25,400 unrestricted common units and 9,000 equity-settled phantom units.

Note 16. Supplementary Information

Quarterly data (unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per unit amounts)			
2016				
Oil and natural gas sales	$ 11,269	$ 14,777	$ 14,410	$ 15,642
Gain (loss) on derivatives, net	$ 2,568	$ (10,088)	$ (444)	$ (4,238)
Total revenues and other	$ 13,837	$ 4,689	$ 13,966	$ 11,404
Gain (loss) on sale of properties	$ —	$ 13	$ (530)	$ (43)
Total expenses (1)	$ 17,150	$ 20,471	$ 15,857	$ 14,672
Net loss	$ (3,313)	$ (15,769)	$ (2,421)	$ (3,311)
Net loss per limited partner unit (basic and diluted)	$ (0.11)	$ (0.52)	$ (0.09)	$ (0.14)
2015				
Oil and natural gas sales	$ 17,571	$ 21,611	$ 18,493	$ 16,239
Gain (loss) on derivatives, net	$ 1,644	$ (8,871)	$ 19,771	$ 9,822
Total revenues and other	$ 19,215	$ 12,740	$ 38,264	$ 26,061
Total expenses (1)	$ 23,327	$ 20,684	$ 63,742	$ 84,022
Net loss	$ (4,112)	$ (7,944)	$ (25,478)	$ (57,961)
Net loss per limited partner unit (basic and diluted)	$ (0.14)	$ (0.26)	$ (0.85)	$ (1.93)

(1) Includes the following expenses: lease operating, production taxes, impairment, depreciation, depletion and amortization, accretion, general and administrative and net other income (expense).

Supplementary oil and natural gas activities

Costs incurred in oil and natural gas property acquisitions and development activities are as follows:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Property acquisition costs:			
Proved	$ 18,722	$ 1	$ 241,355
Unproved	—	—	—
Exploration	—	—	—
Development	6,963	13,415	34,320
Asset retirement obligations	902	4,924	3,171
Total costs incurred	$ 26,587	$ 18,340	$ 278,846

Estimated proved oil and natural gas reserves (unaudited)

The Partnership's proved oil and natural gas reserves are all located in the United States. The proved oil and natural gas reserves for the years ended December 31, 2016, 2015 and 2014 were prepared by our reservoir engineers and audited by Cawley, Gillespie & Associates, Inc., independent third party petroleum consultants. These reserve estimates have been prepared in compliance with the rules of the SEC. We emphasize that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates are expected to change as future information becomes available.

An analysis of the change in estimated quantities of oil and natural gas reserves are presented below for the periods indicated:

	Oil (MBbls)	Natural Gas (MMcf)	MBoe
Proved developed and undeveloped reserves:			
As of December 31, 2013	13,714	1,321	13,934
Revisions of previous estimates [1]	211	924	364
Extensions, discoveries and other additions	1,241	52	1,250
Purchases of reserves in place	8,086	4,402	8,820
Production	(1,112)	(157)	(1,138)
As of December 31, 2014	22,140	6,542	23,230
Revisions of previous estimates [1]	596	856	739
Extensions, discoveries and other additions	—	—	—
Purchases of reserves in place	1	—	1
Production	(1,623)	(571)	(1,718)
As of December 31, 2015	21,114	6,827	22,252
Revisions of previous estimates [1]	58	(262)	14
Extensions, discoveries and other additions	—	—	—
Purchases of reserves in place [2]	1,517	211	1,552
Sales of reserves in place [3]	(3,093)	(98)	(3,109)
Production	(1,386)	(554)	(1,478)
As of December 31, 2016	18,210	6,124	19,231
Proved developed reserves:			
December 31, 2014	17,046	5,327	17,933
December 31, 2015	14,368	4,762	15,162
December 31, 2016	11,733	4,141	12,423
Proved undeveloped reserves:			
December 31, 2014	5,094	1,215	5,297
December 31, 2015	6,746	2,065	7,090
December 31, 2016	6,477	1,983	6,808

(1) Revisions represent changes in the previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such a commodity prices, operating costs or development costs.

(2) Represents the purchase of proved reserves as part of our Permian Bolt-On acquisition.

(3) Decrease due to the sale of our Hugoton core area oil and natural gas properties.

The change in quantities of proved reserves from December 31, 2013 to December 31, 2014, was due to the acquisitions of additional properties in Oklahoma and Texas from our affiliate Mid-Con Energy III, LLC, the acquisition of additional working interest in some of our Southern Oklahoma properties, the acquisition of the waterflood unit in Liberty County, Texas and the acquisition of multiple properties located in West Texas within the Eastern Shelf of the Permian. For this period, proved reserve volumes attributed to extensions, discoveries and other additions changed from 76 MBoe in 2013 to 1,250 MBoe in 2014. During the period of 2014, extensions, discoveries and other additions increased over the prior year primarily from development work in the Northeastern Oklahoma area, which increased proved developed producing and proved undeveloped reserves from new reservoirs from portions of older fields.

The change in quantities of proved reserves from December 31, 2014 to December 31, 2015, was due to a significant commodity price decrease that resulted in a downward revision of 4,084 MBoe, improved recovery of 1,417 MBoe from our proved developed reserves in addition to 994 MBoe transferred from proved undeveloped reserves to proved developed reserves and the addition of recompletions, infill drilling, new waterflood projects, and expansion of existing waterflood projects in our Hugoton, Northeastern Oklahoma, Southern Oklahoma and Permian core areas resulting in a positive revision of proved undeveloped reserves of 3,405 MBoe. The upward revision of our proved developed reserves is largely attributable to a positive oil production response in 2015 to recently established water injection in the Cleveland Unit (Northeastern Oklahoma), Ona Morrow Unit (Hugoton) and Midwell Unit (Hugoton).

The change in quantities of proved reserves from December 31, 2015 to December 31, 2016, was due in part to commodity price decreases which shortened the economic lives of certain producing properties and caused certain development projects to become uneconomic which had an adverse impact on our proved reserves estimates, resulting in downward reserve revisions of 1,801 MBoe in 2016. In response to the continued decrease in commodity prices throughout 2016, we further refined our development plans to concentrate on our Northeastern Oklahoma and Permian core areas. This included infill drills and recompletions resulting in positive revisions in production performance of 569 MBoe. In addition, we saw positive oil production responses to water injection in our Northeastern Oklahoma and Permian core areas, resulting in upward revisions to our proved reserves of 1,246 MBoe. During 2016, the divestiture of our Hugoton core area properties resulted in a downward revision of 3,109 MBoe and the acquisition of the Permian Bolt-On properties resulted in a positive revision of 1,552 MBoe.

Estimates of economically recoverable oil and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil and natural gas may differ materially from the amounts estimated.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves (Unaudited)

The Standardized Measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, production, plugging and abandonment costs, discounted at the rate prescribed by the SEC. The Standardized Measure of discounted future net cash flow does not purport to be, nor should it be interpreted to represent, the fair market value of our proved oil and natural gas reserves. The following assumptions have been made:

- In the determination of future cash inflows, sales prices used for oil and natural gas for the years ended December 31, 2016, 2015 and 2014, were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month in such period.
- Future costs of developing and producing the proved oil and natural gas reserves were based on costs determined at each such period-end, assuming the continuation of existing economic conditions, including abandonment costs.
- No future income tax expenses are computed for Mid-Con Energy Partners, LP because we are a non-taxable entity.
- Future net cash flows were discounted at an annual rate of 10% .

The Standardized Measure of discounted future net cash flow relating to estimated proved oil and natural gas reserves is presented below for the periods indicated:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Future cash inflows	$ 741,077	$ 1,011,096	$ 2,084,005
Future production costs	(389,138)	(581,314)	(825,318)
Future development costs, including abandonment costs	(65,195)	(109,669)	(76,783)
Future net cash flow	286,744	320,113	1,181,904
10% discount for estimated timing of cash flow	(129,459)	(128,693)	(517,627)
Standardized measure of discounted cash flow	$ 157,285	$ 191,420	$ 664,277

The prices utilized in calculating our total proved reserves were $42.75 , $50.28 and $94.99 per Bbl of oil and $2.49 , $2.58 and $4.35 per MMBtu of natural gas for December 31, 2016, 2015 and 2014, respectively. These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions or other factors affecting the price received at the wellhead. Average adjusted prices used were $40.03 , $47.23 and $92.45 per Bbl of oil and $1.99 , $2.02 and $5.67 per Mcf of natural gas for December 31, 2016, 2015 and 2014, respectively. Adjusted natural gas price includes the sale of associated NGLs. We do not extract NGLs from our natural gas production prior to the sale and transfer of title of the natural gas stream to our purchasers. While some of our purchasers extract NGLs from the natural gas stream sold by us to them, we have no ownership in such NGLs; therefore, we do not report NGLs in our production or proved reserves. All wellhead prices are held flat over the life of the properties for all reserve categories.

Changes in the Standardized Measure of discounted future net cash flow relating to proved oil and natural gas reserves is presented below for the periods indicated:

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Standardized measure of discounted future net cash flow, beginning of period	$ 191,420	$ 664,277	$ 391,263
Changes in the year resulting from:			
Sales, less production costs	(30,513)	(36,836)	(64,495)
Revisions of previous quantity estimates	133	8,047	11,712
Extensions, discoveries and improved recovery	—	—	44,727
Net change in prices and production costs	(16,138)	(454,669)	22,068
Net change in income taxes	—	—	—
Changes in estimated future development costs	22,685	(6,080)	(18,125)
Previously estimated development costs incurred during the period	3,526	8,103	22,526
Purchases of reserves in place	22,223	19	264,921
Sales of reserves in place	(11,124)	—	—
Accretion of discount	19,142	66,428	39,126
Timing differences and other	(44,069)	(57,869)	(49,446)
Standardized measure of discounted future net cash flow, end of year	$ 157,285	$ 191,420	$ 664,277

ITEM 9. CHANGES IN AND DISAGREEMETS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 December 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 file 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-K.

Management's Report on Internal Control over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our internal control system was designed to provide reasonable assurance to our Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Mid-Con Energy Partners, LP's internal control over financial reporting was effective as of December 31, 2016.

/s/ Jeffrey R. Olmstead	/s/ Matthew R. Lewis
Jeffrey R. Olmstead Chief Executive Officer	Matthew R. Lewis Chief Financial Officer

February 28, 2017

Change 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 period covered by this Form 10-K 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.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

As is the case with many publicly traded partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by our general partner. References to our officers and Board of Directors therefore refer to the officers and Board of Directors of our general partner. Our general partner is controlled by Charles R. Olmstead and Jeffrey R. Olmstead, the voting members of our general partner.

Our general partner is not elected by our unitholders and is not subject to re-election on an annual or other continuing basis in the future. In addition, our unitholders are not entitled to elect the directors of our general partner, nor are they directly or indirectly entitled to participate in our management or operations. Further, our partnership agreement, like many master limited partnership agreements, contains provisions that substantially restrict the fiduciary duties that our general partner would otherwise owe to our unitholders under Delaware law.

The Board of Directors of our general partner has seven members. The NASDAQ Global Select Market listing rules do not require a listed limited partnership, like us, to have a majority of independent directors on the Board of Directors of our general partner or to establish a compensation committee or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members, all of whom are required to meet the independence and experience standards established by the NASDAQ Global Select Market listing rules and SEC rules.

All of the executive officers of our general partner are also officers and/or directors of Mid-Con Affiliates. The executive officers of our general partner allocate their time between managing our business and affairs and the business and affairs of Mid-Con Affiliates. In addition, employees of Mid-Con Energy Operating provide management, administrative and operational services to us pursuant to the services agreement, but they also provide these services to Mid-Con Affiliates.

Directors and Executive Officers

The following table sets forth certain information regarding the current directors and executive officers of our general partner. At December 31, 2016, the average tenure of the individuals listed below was approximately four years since the Initial Public Offering in December 2011.

Name	Age	Position with Mid-Con Energy GP, LLC
Charles R. "Randy" Olmstead	68	Executive Chairman of the Board
Jeffrey R. Olmstead	40	President, Chief Executive Officer and Director
Matthew R. Lewis	30	Vice President, Chief Financial Officer
Charles L. McLawhorn III	40	Vice President, General Counsel and Corporate Secretary
Sherry L. Morgan	49	Chief Accounting Officer
Peter Adamson III (1)	75	Director
C. Fred Ball Jr. (2)	72	Director
Wilkie S. Colyer Jr.	32	Director
Peter A. Leidel	60	Director
Cameron O. Smith (1)	66	Director

(1) Member of the audit committee and the conflicts committee.

(2) Member of the audit committee.

The members of our general partner's Board of Directors are appointed for one-year terms by Charles R. Olmstead and Jeffrey R. Olmstead, the voting members of our general partner, and hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been appointed and qualified. The executive officers of our general partner serve at the discretion of the Board of Directors. All of our general partner's executive officers also serve as executive officers of the Mid-Con Affiliate. Charles R. Olmstead and Jeffrey R. Olmstead are father and son, respectively. There are no other family relationships among our general partner's executive officers and directors.

Charles R. "Randy" Olmstead serves as Executive Chairman of the Board of Directors of our general partner. Mr. Olmstead previously served as Chief Executive Officer and Chairman of the Board of Directors of our general partner and Mid-Con Energy III, LLC from June 2011 until August 2014. Mr. Olmstead served as President, Chief Financial Officer and Chairman of the Board of Directors of Mid-Con Energy I, LLC from its formation in 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. He has been President, Chief Financial Officer and Chairman of the Board of Directors of Mid-Con Energy Operating since its incorporation in 1986. Prior to that, Mr. Olmstead was general manager for LB Jackson Drilling Company from 1978 to 1980 and worked in public accounting for Touche Ross & Co. from 1974 to 1978 as an oil and natural gas tax consultant. Mr. Olmstead graduated with Bachelors of Business Administration degrees in Finance and Accounting from the University of Oklahoma before serving three years in the US Navy. Mr. Olmstead brings to our Board of Directors extensive management and operational experience in the oil and natural gas industry, along with his leadership skills.

Jeffrey R. Olmstead serves as President, Chief Executive Officer and as a member of the Board of Directors of our general partner. Mr. Olmstead previously served as President, Chief Financial Officer of our general partner and Mid-Con Energy III, LLC from June 2011 until August 2014. Mr. Olmstead was a member of the Board of Directors of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC from 2007 until both entities were merged into us in December 2011. Mr. Olmstead previously served as Chief Financial Officer and Vice President of Primexx Energy Partners, Ltd., a privately held exploration and production company, from May 2010 until July 2011. From August 2006 until May 2010, Mr. Olmstead served as an Assistant Vice President at Bank of Texas/Bank of Oklahoma. Mr. Olmstead holds a Bachelor of Engineering degree in Electrical Engineering and Math from Vanderbilt University and a Master of Business Administration degree from the Owen School of Business at Vanderbilt University. Mr. Olmstead brings to our Board of Directors knowledge of the oil and natural gas industry and his finance background provides a critical resource.

Matthew R. Lewis serves as Vice President and Chief Financial Officer of our general partner. Mr. Lewis became an officer of our general partner in August 2016. Mr. Lewis joined Mid-Con Energy in 2011, having most recently served as Director of Strategic Planning & Financial Analysis. From 2010 to 2011, Mr. Lewis served as an Associate at Primexx Energy Partners, Ltd., a privately held oil and natural gas company, after spending two years at ORIX USA in the middle-market leveraged finance group. Mr. Lewis holds a Bachelor of Business Administration degree in Finance from Texas Tech University and a Master of Business Administration degree from the Cox School of Business at Southern Methodist University.

Charles L. McLawhorn III serves as Vice President, General Counsel and Corporate Secretary of our general partner. Mr. McLawhorn became an officer of our general partner in April 2016. From August 2009 to March 2016, Mr. McLawhorn held a series of positions with increasing responsibility, including Assistant General Counsel and Corporate Secretary, at Samson Resources Corporation. Earlier in his career, Mr. McLawhorn was in private practice with McAfee & Taft from 2002 to 2009. Mr. McLawhorn graduated with a Bachelor of Science degree in Zoology from the University of Oklahoma and holds a Juris Doctor degree from the University of Oklahoma College of Law.

Sherry L. Morgan serves as Chief Accounting Officer of our general partner. Ms. Morgan became an officer of our general partner in July 2015, and previously served as our Assistant Controller from July 2008 until July 2015. Prior to joining us, Ms. Morgan served as Controller at Shamrock Oil & Gas, Inc. from 2006 to 2008. She also served as Controller for Nadel and Gussman, LLC during 2006. Ms. Morgan served as Reporting and Joint Interest Coordinator at Newfield Exploration Mid-Continent, Inc. from 2000 to 2005. Previously, she was Assistant Controller at both Lariat Petroleum, Inc. and First Credit Solutions. Ms. Morgan began her career as an auditor at Deloitte and Touche, LLP. Ms. Morgan earned her Bachelor of Science in Business Administration with a degree in Accounting from Oklahoma State University. She is a Certified Public Accountant and a Certified Management Accountant.

Peter Adamson III serves as a member of the Board of Directors of our general partner and is also chairman of the audit committee. Mr. Adamson is currently the managing member of Autumn Glory Partners, LLC, a private consulting firm. Prior to Autumn Glory Partners, LLC, Mr. Adamson was a founder of Adams Hall Asset Management, LLC, a Tulsa, Oklahoma, based registered investment advisor with over $1 billion under management and still serves as a consultant. Prior to forming Adams Hall in 1997, Mr. Adamson was an owner and principal of Houchin, Adamson & Co., Inc., a registered broker-dealer formed in 1980. Mr. Adamson is founding co-investor and advisor to Horizon Well Logging, a leading provider of geological field services. Mr. Adamson serves on the advisory board of the Michel F. Price College of Business at the University of Oklahoma and serves on the University of Oklahoma asset oversight committee. Mr. Adamson received his Bachelor of Business Administration degree in Accounting from the University of Oklahoma. Mr. Adamson brings to our Board of Directors a breadth knowledge across the disciplines of finance and accounting.

C. Fred Ball Jr. serves as a member of the Board of Directors of our general partner. Mr. Ball also currently serves as Chief Operating Officer of Spyglass Trading, LP. Mr. Ball retired in January 2015 as Senior Chairman of the Board for Bank of Texas, a division of BOK Financial Corporation. During his 17 year tenure at Bank of Texas, Mr. Ball was elected to various executive positions including President, Chief Executive Officer and Chairman. Prior to Bank of Texas, he served as President of Comerica Securities, Inc., a subsidiary of Comerica Incorporated in Detroit. Mr. Ball currently serves on the Board of Directors for BOK Financial Corporation, the National Teachers Associates Life Insurance Company, where he is also a member of the audit committee, and at Southern Methodist University, where he resides on both the Executive Board of the Edwin L. Cox School of Business and the Executive Board of the Lyle School of Engineering. Mr. Ball earned his Bachelor of Science in Engineering and Master of Business Administration from Southern Methodist University. Mr. Ball brings to our Board of Directors extensive insights and the knowledge of finance and banking.

Wilkie S. Colyer Jr. serves as a member of the Board of Directors of our general partner. Mr. Colyer currently serves as a Principal for Goff Capital, Inc. ("Goff Capital"), the family office of John C. Goff, which indirectly holds a significant number of the Partnership's Preferred Units. Since joining Goff Capital in 2007, Mr. Colyer has led or played a material role in public and private investments in sectors including energy, financial services, and real estate, among others. Mr. Colyer received a Bachelor of Arts in Economics from the University of Texas at Austin. Mr. Colyer holds the Chartered Financial Analyst ("CFA") designation and is a member of the CFA Society of Dallas-Fort Worth. Mr. Colyer brings to our Board of Directors extensive insight into energy and finance.

Peter A. Leidel serves as a member of the Board of Directors of our general partner. Mr. Leidel is a founder and principal of Yorktown Partners, LLC, which was established in September 1990. Yorktown Partners, LLC is the manager of private investment partnerships that invest in the energy industry. Mr. Leidel has been a member of the Board of Directors of Mid-Con Energy III, LLC and Mid-Con Energy Operating since June 2011. Mr. Leidel was a member of the Board of Directors of Mid-Con Energy I, LLC from its formation in 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. Previously, he was a partner of Dillon, Read & Co. Inc., held corporate treasury positions at Mobil Corporation, worked for KPMG and for the U.S. Patent and Trademark Office. Mr. Leidel is a director of certain non-public companies in the energy industry in which Yorktown holds equity interests. Mr. Leidel earned a Bachelor of Business Administration degree in Accounting from the University of Wisconsin and a Master of Business Administration from the Wharton School at the University of Pennsylvania. Mr. Leidel brings to our Board of Directors extensive private experience within and perspective on the energy sector.

Cameron O. Smith serves as a member of the Board of Directors of our general partner and is also chairman of the conflicts committee. From 2008 until December 2009, Mr. Smith served as a Senior Managing Director of Rodman & Renshaw, LLC and as Head of The Rodman Energy Group, a sector vertical within Rodman & Renshaw, LLC. Mr. Smith retired from The Rodman Energy Group in December 2009. Mr. Smith founded and from 1992 to 2008, served as a Senior Managing Director of COSCO Capital Management, LLC, an investment bank focused on private oil and natural gas corporate and project financing until Rodman & Renshaw, LLC, a full service investment bank, purchased the business and assets of COSCO Capital Management, LLC. Mr. Smith founded and ran Taconic Petroleum Corporation, an exploration company headquartered in Tulsa, Oklahoma, from 1978 to 1991. Mr. Smith served as exploration geologist, officer and director of several private family and public client companies from 1975 to 1985. Mr. Smith graduated with a Bachelor of Arts in Art

History from Princeton University and a Master of Science degree in Geology from Pennsylvania State University. Mr. Smith brings to our Board of Directors extensive knowledge of the oil and natural gas industry, along with expertise in investment banking.

Committees of the Board of Directors

The Board of Directors of Mid-Con Energy GP, LLC has an audit committee and a conflicts committee, but does not have a compensation committee. The NASDAQ Global Select Market listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee. Our Board of Directors or an appointed committee, currently comprised of Charles R. Olmstead and Jeffrey R. Olmstead, the voting members of our general partner, approve equity grants to directors and employees.

Audit Committee

The audit committee consists of Messrs. Adamson, Ball, and Smith, with Mr. Adamson serving as committee chairman. Our Board of Directors have affirmatively determined that each member of the audit committee meets the independence and experience standards established by the NASDAQ Global Select Market listing rules and the rules of the SEC. Our Board of Directors have also reviewed the financial expertise of Mr. Adamson and affirmatively determined that he is an "audit committee financial expert," as determined by the rules of the SEC. Our Board of Directors has adopted a written charter for our audit committee which is available on, and may be printed from, our website at www.midconenergypartners.com and is also available from the corporate secretary of Mid-Con Energy GP, LLC.

The audit committee held four meetings in 2016. The audit committee assists the Board of Directors in its oversight of the integrity of our financial statements, compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to retain or terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary.

Conflicts Committee

The conflicts committee consists of Messrs. Smith and Adamson, both of whom meet the independence standards established by the NASDAQ Global Select Market listing rules and rules of the SEC. The conflicts committee has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict is "fair and reasonable" for our unitholders. In making such determination, the conflicts committee has the authority to engage advisors to assist it in carrying its duties. The conflicts committee did not hold any meetings in 2016.

Board Leadership Structure and Role in Risk Oversight

Leadership of our general partner's Board of Directors is vested in a Chairman of the Board. Although our Chief Executive Officer currently does not serve as Chairman of the Board of Directors of our general partner, we currently have no policy prohibiting our current, or any future chief executive officer, from serving as Chairman of the Board. The Board of Directors, in recognizing the importance of its ability to operate independently, determined that separating the roles of Chairman of the Board and Chief Executive Officer is advantageous for us and our unitholders at this time. Our general partner's Board of Directors has also determined that having the Chief Executive Officer serve as a director will enhance understanding and communication between management and the Board of Directors, allow for better comprehension and evaluation of our operations and ultimately improve the ability of the Board of Directors to perform its oversight role.

The management of enterprise-level risk is the process of identifying, managing and monitoring events that present opportunities and risks with respect to the creation of value for our unitholders. The Board of Directors of our general partner has delegated to management the primary responsibility for enterprise-level risk management, while retaining responsibility for oversight of our executive officers in that regard. Our executive officers offer an enterprise-level risk assessment to the Board of Directors at least once every year.

Non-Management Executive Sessions and Unitholder Communications

NASDAQ Global Select Market listing standards require regular executive sessions of the non-management directors of a listed company, and an executive session for independent directors at least once a year. At each quarterly meeting of our general partner's Board of Directors, all of the directors meet in an executive session. At least annually, our independent directors meet in an additional executive session without management participation or participation by non-independent directors.

Interested parties can communicate directly with non-management directors by mail in care of Mid-Con Energy Partners, LP, 2431 East 61 Street, Suite 850, Tulsa, Oklahoma 74136. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Meetings and Other Information

The Board of Directors held six meetings in 2016.

Our partnership agreement provides that the general partner manages and operates us and that, unlike holders of common stock in a corporation, unitholders only have limited voting rights on matters affecting our business or governance. Accordingly, we do not hold annual meetings of unitholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and directors of our general partner and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and the NASDAQ Global Select Market concerning their beneficial ownership of such securities. Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of our general partner, we believe that all filing requirements applicable to the officers and directors of our general partner and greater than 10% unitholders were complied with for the fiscal year ended December 31, 2016.

Code of Ethics

The governance of Mid-Con Energy GP, LLC is, in effect, the governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Mid-Con Energy GP, LLC has adopted a Code of Business Conduct that applies to all officers, directors and employees of Mid-Con Energy GP, LLC and its affiliates. A copy of our Code of Business Conduct is available on our website at www.midconenergypartners.com . We will provide a copy of our code of ethics to any person, without charge, upon request to Mid-Con Energy Partners, LP, 2431 East 61 Street, Suite 850, Tulsa, Oklahoma 74136, Attn: Investor Relations.

Web Access

We provide access through our website at www.midconenergypartners.com to current information relating to partnership governance, including our Audit Committee Charter, our Code of Business Conduct and other matters impacting our governance principles. You may access copies of each of these documents from our website. You may also contact the office of the corporate secretary of our general partner for printed copies of these documents free of charge. Our website and any contents thereof are not incorporated by reference into this document.

Communication with Directors

Our Board of Directors believes that it is management's role to speak for the partnership. Our Board of Directors also believes that any communications between members of the Board of Directors and interested parties, including unitholders, should be conducted with the knowledge of our executive chairman, president and chief executive officer. Interested parties, including unitholders, may contact one or more members of our Board of Directors, including non-management directors and non-management directors as a group, by writing to the director or directors in care of the corporate secretary of our general partner at our principal executive offices. A communication received from an interested party or unitholder will be promptly forwarded to the director or directors to whom the communication is addressed. A copy of the communication will also be provided to our executive chairman and chief executive officer. We will not, however, forward sales or marketing materials or correspondence primarily commercial in nature, materials that are abusive, threatening or otherwise inappropriate, or correspondence not clearly identified as interested party or unitholder correspondence.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General

We do not directly employ any of the persons responsible for managing our business. Our general partner's executive officers manage and operate our business as part of the services provided by Mid-Con Energy Operating to our general partner under the services agreement. All of our general partner's executive officers and other employees necessary to operate our business are employed and compensated by Mid-Con Energy Operating, subject to reimbursement by our general partner. The compensation for all of our executive officers is indirectly paid by us to the extent provided for in the partnership agreement because we reimburse our general partner for payments it makes to Mid-Con Energy Operating.

Compensation Committee Report

The NASDAQ Global Select Market listing rules do not require a listed limited partnership to establish a compensation committee, and we do not have a compensation committee. The Board of Directors of our general partner performs the functions of a compensation committee, and although the Board of Directors of our general partner does not currently appoint a compensation committee, it may do so in the future. The Board of Directors of our general partner has reviewed and discussed with management the Compensation Discussion and Analysis, or CD&A, set forth below.

Our "named executive officers" for the year ended December 31, 2016, were:

Charles R. "Randy" Olmstead
Jeffrey R. Olmstead
Matthew R. Lewis
Michael D. Peterson
Charles L. McLawhorn III
Sherry L. Morgan

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this Annual Report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under those Acts.

Objectives of Our Compensation Program

Our executive compensation program is intended to align the interests of our management team with those of our unitholders by motivating our executive officers to achieve strong financial and operating results for us, which we believe closely correlate to long-term unitholder value. In addition, our program is designed to achieve the following objectives:

- attract, retain and reward talented executive officers by providing total compensation competitive with that of other executive officers employed by exploration and production companies and publicly traded partnerships of similar size;
- provide performance-based compensation that balances rewards for short-term and long-term results and is tied to both individual and our performance; and
- encourage the long-term commitment of our executive officers to us and our unitholders' long-term interests.

Elements of Our Compensation Program and Why We Pay Each Element

To accomplish our objectives, we seek to offer a compensation program to our executive officers that, when valued in its entirety, serves to attract, motivate and retain executives with the character and expertise required for our growth and development. Our compensation program is comprised of four elements:

- base salary;
- discretionary cash bonus;
- long-term equity-based compensation; and
- benefits.

Charles R. Olmstead and Jeffrey R. Olmstead, as the controlling members of our general partner, have responsibility and authority for compensation-related decisions for our Chief Executive Officer and, upon consultation and recommendations by our Chief Executive Officer, for our other executive officers. Equity grants pursuant to our Long-Term Incentive Program are also administered by the controlling members of our general partner.

Our general partner also grants equity-based awards to our executive officers pursuant to a Long-Term Incentive Program described below. Incentive compensation in respect of services provided to us is not tied in any way to the performance of entities other than our partnership. Specifically, any performance metrics are not to be tied in any way to the performance of the Mid-Con Affiliates or any other affiliate of ours.

Although we bear an allocated portion of Mid-Con Energy Operating's costs of providing compensation and benefits to Mid-Con Energy Operating employees who serve as the executive officers of our general partner and provide services to us, we have no control over such costs and do not establish or direct the compensation policies or practices of Mid-Con Energy Operating.

Mid-Con Energy Operating does not maintain a defined benefit or pension plan for its executive officers or employees because it believes such plans primarily reward longevity rather than performance. Mid-Con Energy Operating provides a basic benefits package to all its employees, which includes a 401(k) plan, health and basic term life insurance and personal accident and long-term disability coverage. Employees provided to us under the services agreement will be entitled to the same basic benefits.

Employment Agreements

Our general partner has entered into employment agreements with Charles R. Olmstead, Executive Chairman of the Board of our general partner and Jeffrey R. Olmstead, President and Chief Executive Officer. The previous employment agreement with S. Craig George was terminated in August 2014.

The employment agreements provide for a term that commences on August 1 of each year with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. 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 employment agreements also provide for customary confidentiality, non-solicitation, non-compete and indemnification protections. The non-solicitation provisions prohibit an executive from soliciting persons to leave our employment who are employed by us within six months before or after the executive's termination. This restriction continues during the term of and for twelve months following termination of the executive's employment, and also for twelve months following the termination of the solicited employee's employment. The non-solicitation provisions also prohibit an executive from soliciting our customers during the term of and for twelve months following termination of the executive's employment. The non-competition provisions prohibit the executive from competing with us during the term of the executive's employment and for a period during which severance payments are being made to the executive, which by the terms of the agreements may be up to two years after the executive's separation of employment.

Long-Term Incentive Program

Our Long-Term Incentive Program which is intended to promote the interests of the partnership by providing to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating and ME3 Oilfield Service, grants of restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, and other unit based awards to encourage superior performance. The Long-Term Incentive Program is also intended to enhance the ability of the general partner and our other affiliates, including Mid-Con Energy Operating and ME3 Oilfield Service, to attract and retain the services of individuals who are essential for the growth and profitability of the partnership and to encourage them to devote their best efforts to advancing the business of the partnership.

The Long-Term Incentive Program is currently administered by a committee consisting of Charles R. Olmstead and Jeffrey R. Olmstead, the voting members of our general partner, and approved by the Board of Directors. Except as set forth in the employment agreements of the executive officers of our general partner, we have no set formula for granting awards to our employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating and ME3 Oilfield Service. In determining whether to grant awards and the amount of any awards, the committee takes into consideration discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package.

The type of awards that may be granted under the Long-Term Incentive Program are unit options, unit appreciation rights, unrestricted units, restricted units, phantom units, distribution equivalent rights granted with phantom units and other types of awards. The maximum number of our common units that are currently authorized to be awarded under the Plan is 3,514,000 units. As of December 31, 2016, there were 1,468,770 units available for issuance.

Equity Compensation Plan Information:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	—	1,468,770 [1]
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	1,468,770

[1] Represents common units.

The plan administrator may terminate or amend the Long-Term Incentive Program at any time with respect to any units for which a grant has not yet been made. The plan administrator also has the right to alter or amend the Long-Term Incentive Program or any part of the Long-Term Incentive Program from time to time, including increasing the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the rights or benefits of the participant without the consent of the participant. The Long-Term Incentive Program will expire on the earliest to occur of (i) the date on which all common units available under the Plan for grants have been paid to participants, (ii) termination of the Plan by the plan administrator or (iii) December 20, 2021.

Upon a "change of control" (as defined in the Long-Term Incentive Program), any change in applicable law or regulation affecting the Long-Term Incentive Program or awards thereunder, or any change in accounting principles affecting the financial statements of our general partner, the plan administrator, in an attempt to prevent dilution or enlargement of any benefits available under the Long-Term Incentive Program may, in its discretion, provide that awards will (i) become exercisable or payable, as applicable, (ii) be exchanged for cash, (iii) be replaced with other rights or property selected by the plan administrator, (iv) be assumed by the successor or survivor entity or be exchanged for similar options, rights or awards covering the equity of such successor or survivor, or a parent or subsidiary thereof, with other appropriate adjustments or (v) be terminated. Additionally, the plan administrator may also, in its discretion, make adjustments to the terms and conditions, vesting and performance criteria and the number and type of common units, other securities or property subject to outstanding awards.

The consequences of the termination of a grantee's employment, consulting arrangement or membership on the Board of Directors will be determined by the plan administrator in the terms of the relevant award agreement or employment agreement.

Common units to be delivered pursuant to awards under the Long-Term Incentive Program may be common units already owned by our general partner or us or acquired by our general partner in the open market from any other person, directly from us or any combination of the foregoing. If we issue new common units upon the grant, vesting or payment of awards under the Long-Term Incentive Program, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash, our general partner will be entitled to reimbursement by us for the amount of the cash settlement.

Short-Term Incentive Payments

Short-term incentive payments are provided to executive officers to recognize and reward their overall performance as determined by the Board of Directors of our general partner. We do not provide perquisites to the named executive officers, other than one-time relocation expenses that were provided to Mr. Lewis.

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers for services rendered in all capacities to us and our subsidiaries for the years ended December 31, 2016, 2015 and 2014. All of these employees are paid by Mid-Con Energy Operating. We reimburse Mid-Con Energy Operating for a portion of their compensation according to the services agreement entered between us and Mid-Con Energy Operating.

Name and Principal Position	Year	Salary	Bonus	Unit Awards	All Other Compensation	Total
				(in thousands)		
Charles R. Olmstead	2016	$ 117	$ 70	$ 92	$ 6 (4)	$ 285
Executive Chairman of the Board	2015	$ 156	$ —	$ 524	$ —	$ 680
	2014	$ 191	$ 202	$ 1,273	$ —	$ 1,666
Jeffrey R. Olmstead	2016	$ 252	$ 70	$ 92	$ 10 (4)	$ 424
President, CEO and Director	2015	$ 315	$ —	$ 524	$ —	$ 839
	2014	$ 356	$ 269	$ 1,273	$ —	$ 1,898
Matthew R. Lewis [1]						
VP, Chief Financial Officer	2016	$ 162	$ 41	$ 37	$ 30 (5)	$ 270
Michael D. Peterson [1]	2016	$ 117	$ —	$ —	$ 63 (6)	$ 180
VP, Chief Financial Officer	2015	$ 200	$ 56	$ 78	$ —	$ 334
	2014	$ 108	$ 20	$ 72	$ —	$ 200
Charles L. McLawhorn III [2]	2016	$ 109	$ 43	$ 55	$ 3 (4)	$ 210
VP, General Counsel and Secretary						
Sherry L. Morgan [3]	2016	$ 120	$ 37	$ 37	$ 5 (4)	$ 199
Chief Accounting Officer	2015	$ 101	$ 18	$ 15	$ —	$ 134

(1) Mr. Lewis became Chief Financial Officer during 2016, replacing Mr. Peterson .
(2) Mr. McLawhorn became General Counsel and Corporate Secretary during 2016.
(3) Ms. Morgan became Chief Accounting Officer during 2015.
(4) Includes Registrant's contributions to a defined contribution plan.
(5) Includes approximately $6,000 in Registrant's contributions to a defined contribution plan and approximately $24,000 in relocation expenses.
(6) Includes approximately $4,000 in Registrant's contributions to a defined contribution plan and approximately $59,000 in severance.

Grants of Plan-Based Awards

The following table sets forth certain information with respect to grants of plan-based awards to our named executive officers in 2016. All grants in 2016 were of equity-settled phantom awards with one-third vested immediately and the remaining two-thirds vesting over a two year period. There were no grants of non-equity incentives or option awards.

Name	Grant Date	Unit Awards	Grant Date Fair Value of Unit Awards
Charles R. Olmstead	7/20/2016	50,000	$ 92,000
Jeffrey R. Olmstead	7/20/2016	50,000	$ 92,000
Matthew R. Lewis	7/20/2016	20,000	$ 36,800
Charles L. McLawhorn III	7/20/2016	30,000	$ 55,200
Sherry L. Morgan	7/20/2016	20,000	$ 36,800

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2016:

Name	Number of Units That Have Not Yet Vested		Market Value of Units That Have Not Yet Vested [1]
Charles R. Olmstead	16,666	(2)	$ 43,332
	33,333	(3)	$ 86,666
Jeffrey R. Olmstead	16,666	(2)	$ 43,332
	33,333	(3)	$ 86,666
Matthew R. Lewis	1,000	(2)	$ 2,600
	13,333	(3)	$ 34,666
Charles L. McLawhorn III	20,000	(3)	$ 52,000
Sherry L. Morgan	1,000	(2)	$ 2,600
	13,333	(3)	$ 34,666

(1) Based on the closing price of our common units at December 31, 2016.
(2) These restricted units vest equally over three years beginning January 31, 2015.
(3) These restricted units vest equally over three years beginning July 31, 2016.

Option Exercises and Stock Vested

The following table sets forth stock awards vested during the year ended December 31, 2016. None of our named executive officers had any stock option exercises during 2016.

Name	Number of Shares Acquired on Vesting	Value Realized on Vesting
Charles R. Olmstead	16,667	$ 19,334
	16,667	$ 25,001
Jeffrey R. Olmstead	16,667	$ 19,334
	16,667	$ 25,001
Matthew R. Lewis	535	$ 578
	1,000	$ 1,160
	82	$ 148
	6,667	$ 10,001
Michael D. Peterson	4,000	$ 4,640
	3,125	$ 4,688
	2,000	$ 3,000
Charles L. McLawhorn III	10,000	$ 15,000
Sherry L. Morgan	1,000	$ 1,160
	6,667	$ 10,001

Potential Post-Employment Payments and Payments upon a Change in Control

Payments Made Upon Any Termination – Regardless of the manner in which a named executive officer's employment terminates, he is entitled to receive amounts earned during his term of employment. Such amounts include:

- accrued but unpaid base salary;
- accrued but unpaid vacation pay;
- any unreimbursed business expenses; and
- any accrued benefits.

Payments Made Upon Termination Without "Cause" or For "Good Reason" – Effective August 2011, we entered into employment agreements with each of Charles R. Olmstead and Jeffrey R. Olmstead. In the event of the termination of either of these named executive officers without "cause" or for "good reason" (each as defined in the employment agreements), if the named executive officer executes and does not revoke a general release of claims, in addition to the items identified above, such named executive officer will be entitled to:

- payment of base salary, as in effect immediately prior to termination, multiplied by the greater of the number of years remaining in the employment period and one;
- a lump sum payment to compensate the named executive officer for COBRA health-care coverage for the named executive officer and the named executive officer's dependents (if applicable);
- accelerated vesting and conversion of any units which may have been awarded to the named executive officer through our Long-Term Incentive Program;
- payment of an amount equal to the lesser of the "target annual bonus" (as defined in the employment agreements) and the average of the previous two annual bonuses paid to the named executive officer multiplied by the greater of the number of years remaining in the employment period and one; and
- payment of any unpaid annual bonus that would have become payable to the named executive officer in respect of any calendar year that ends on or before the date of termination had the named executive officer remained employed throughout the payment date of such annual bonus.

Payments Made Upon Death or Disability – In the event of the death or disability of one of these named executive officers, if the officer or his estate executes and does not revoke a general release of claims, in addition to the benefits listed under the heading "Payments Made Upon Any Termination" above, the officer or his estate will be entitled to:

- accelerated vesting and conversion of any units which may have been awarded to the officer through our Long-Term Incentive Program, in accordance with the terms of the applicable award agreement;
- a lump sum payment to compensate the officer or the officer's estate for COBRA health-care coverage for the officer (if living) and the officer's dependents (if applicable);
- a payment equal to the product of the officer's base salary as in effect immediately prior to the date of termination multiplied by one;
- payment of any unpaid annual bonus that would have become payable to the officer in respect of any calendar year that ends on or before the date of termination had the officer remained employed through the payment date of such annual bonus; and
- payment of the target annual bonus for the year in which the officer's separation from service occurs.

Payments Made Upon a Change in Control – Each employment agreement had an initial three-year term and automatically extends in one-year increments after the expiration of the initial term unless we provide written notice of non-renewal to the officer, or the officer provides written notice of non-renewal to us, by at least February 1 preceding the August 1 renewal date. If, during the period beginning sixty days prior to and ending two years immediately following a "change in control," either we terminate the officer's employment without "cause," the officer's death occurs, the officer becomes disabled or the officer terminates his employment for "good reason," then in addition to the benefits listed under the heading "Payments Made Upon Any Termination," the officer will be entitled to:

- payment of base salary, as in effect immediately prior to termination, multiplied by two;
- a lump sum payment to compensate the officer for COBRA health-care coverage for the named executive officer and the officer's dependents (if applicable);

- accelerated vesting and conversion of any units which may have been awarded to the officer through our Long-Term Incentive Program;
- payment of an amount equal to the lesser of the "target annual bonus" (as defined in the employment agreements) and the average of the previous two annual bonuses paid to the officer multiplied by two; and
- payment of any unpaid annual bonus that would have become payable to the officer in respect of any calendar year that ends on or before the date of termination had the officer remained employed throughout the payment date of such annual bonus.

Additionally, if a change in control occurs during the employment period, certain equity-based awards held by the officers, to the extent not previously vested and converted into common units, will vest in full upon such change in control and will be settled in common units in accordance with the applicable award agreements. Relative to our overall value, we believe the potential benefits payable upon a change in control under these agreements are comparatively minor.

For the purposes of these agreements, a "change in control" generally means any of the following events:

- any "person" or "group" within the meaning of those terms as used in Sections 13(d) and 14(d) of the Exchange Act, other than certain of our affiliated entities, shall become the beneficial owner, directly or indirectly, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in us;
- a plan of complete liquidation, in one or a series of transactions, is approved;
- the sale or other disposition by us of all or substantially all of our assets in one or more transactions to any person other than certain of our affiliated entities;
- a transaction resulting in a person other than us or one of certain of our affiliated entities being our general partner; or
- any time at which individuals who, as of October 31, 2011, constituted our Board of Directors (the "Incumbent Board") cease for any reason to constitute at least a majority of our Board; provided, however, that any individual becoming a director subsequent to October 31, 2011, whose election, or nomination for election by our unitholders was approved by a vote of at least a majority of the directors then comprising the Incumbent Board or whose membership was required by any employment agreement with us will be considered as though such individuals were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as the result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Incumbent Board.

For the purposes of these agreements, "cause" means the willful and continued failure of the officer to perform substantially the officer's duties for us (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the officer by the CEO which specifically identifies the manner in which the CEO believes that the officer has not substantially performed the officer's duties and the officer is given a reasonable opportunity of not more than twenty business days to cure any such failure to substantially perform; the willful engaging by the officer in illegal conduct or gross misconduct, including without limitation a material breach of the our Code of Business Conduct or a material breach of the officer's covenants to follow all laws and all of our policies that relate to nondiscrimination and the absence of harassment and to comply with all requirements under the Sarbanes-Oxley Act, in each case which is materially and demonstrably injurious to us; or any act of fraud, or material embezzlement or material theft by the officer, in each case, in connection with the officer's duties hereunder or in the course of the officer's employment hereunder or the officer's admission in any court, or conviction, or plea of nolo contendere, of a felony involving moral turpitude, fraud, or material embezzlement, material theft or material misrepresentation, in each case, against or affecting us. The CEO's determination of materiality of any embezzlement, theft, or misrepresentation, shall be binding and conclusive on the officer.

For the purposes of these agreements, "good reason" means the occurrence of any of the following without the officers written consent: a material diminution in the officer's base salary; a material diminution in the officer's authority, duties, or responsibilities; a material diminution in the budget over which the officer retains authority; a material change (more than 25 miles) in the geographic location at which the officer's primary location of his under his employment agreement; or any other action or inaction that constitutes a material breach by us of the employment agreement.

Potential Post-Employment Payment Tables – The following tables reflect estimates of our allocated portion of the amount of incremental compensation due to each named executive officer subject to an employment agreement in the event of such executive's termination of employment upon death, disability or retirement, termination of employment without cause or termination of employment without cause or with good reason within three years following a change in control. The amounts shown assume that such termination was effective as of December 31, 2016, and are estimates of the allocated amounts which would be paid out to the executives upon such termination. The actual amounts to be paid out can only be determined at the time of such executive's separation of service.

Charles R. Olmstead	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 108,000	$ 108,000	$ 216,000
Restricted Stock/Units	129,998	129,998	129,998
Performance Shares/Units	130,000	130,000	130,000
Health & Welfare	30,222	30,222	30,222
Total	$ 398,220	$ 398,220	$ 506,220

Jeffrey R. Olmstead	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 252,000	$ 252,000	$ 504,000
Restricted Stock/Units	129,998	129,998	129,998
Performance Shares/Units	130,000	130,000	130,000
Health & Welfare	44,748	44,748	44,748
Total	$ 556,746	$ 556,746	$ 808,746

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach performance thresholds which qualify them for additional compensation. From a risk management perspective, our policy is to conduct our commercial activities in a manner intended to control and minimize the potential for unwarranted risk taking. We also routinely monitor and measure the execution and performance of our projects and acquisitions relative to expectations. Additionally, our compensation arrangements include delaying the rewards and subjecting such rewards to forfeiture for terminations related to violations of our risk management policies and practices or of our code of conduct.

Compensation Committee Interlocks and Insider Participation

The NASDAQ Global Select Market listing rules do not require a listed limited partnership to establish a compensation committee, and we do not have a compensation committee. Although the Board of Directors of our general partner does not currently establish a compensation committee, it may do so in the future.

Compensation of Directors

We use a combination of cash and unit-based compensation to attract and retain qualified candidates to serve on our board. In setting director compensation, we consider the significant amount of time that directors expend in fulfilling their duties to us as well as the skill level we require of members of the board.

In 2016, directors who were not officers or employees of us or our affiliates received an annual retainer of $20,000, with the chairman of the audit committee and chairman of the conflict committee receiving an additional annual fee of $5,000. In addition, each non-employee director receives $1,000 per meeting attended in person or by phone and is reimbursed for his out of pocket expenses in connection with attending meetings. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

Each of the independent directors were awarded 4,000 unrestricted common units in January 2016.

The following table discloses the cash, unit awards and other compensation earned, paid or awarded to each of our directors during the year ended December 31, 2016:

Name [(1)]	Fee Earned or Paid in Cash	Unit Awards [(2)]	Total
Peter Adamson III	$ 34,000	$ 4,640	$ 38,640
Cameron O. Smith	$ 34,000	$ 4,640	$ 38,640
Robert W. Berry [(3)]	$ 21,000	$ 4,640	$ 25,640
C. Fred Ball Jr.	$ 29,000	$ 4,640	$ 33,640
Peter A. Leidel	$ 26,000	$ 4,640	$ 30,640
S. Craig George [(4)]	$ 17,500	$ 58,000	$ 75,500

(1) Messrs. Olmstead and Olmstead and not included in this table as they are employees of Mid-Con Energy Operating and receive no compensation for their services as directors.

(2) Reflects the fair value of the units granted in January 2016.

(3) Mr. Berry retired from the Board of Directors effective August 1, 2016.

(4) Mr. George resigned from the Board of Directors effective January 31, 2017.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

As of February 24, 2017, the following table sets forth the beneficial ownership of our common units that are owned by:

- beneficial owners of more than 5% of our common units;
- each executive officer of our general partner; and
- all directors, director nominees and executive officers of our general partner as a group.

Name of Beneficial Owner	Common Units to be Beneficially Owned [(1)]	Percentage of Common Units to be Beneficially Owned	Preferred Units to be Beneficially Owned [(2)]	Percentage of Preferred Units to be Beneficially Owned
Yorktown Energy Partners VI, LP [(3)(4)]	140,436	0.5%	—	—%
Yorktown Energy Partners VII, LP [(3)(5)]	37,207	0.1%	—	
Mid-Con Energy III, LLC [(6)]	3,714,659	12.4%	930,233	8.0%
John C. Goff [(7)]	—	—%	4,790,697	41.2%
Robert W. Stallings [(8)]	—	—%	1,860,465	16.0%
James R. Reis [(8)(9)]	—	—%	1,627,907	14.0%
Bonanza Master Fund, Ltd. [(10)]	—	—%	930,233	8.0%
Charles R. Olmstead [(11)]	740,845	2.5%	—	—%
Jeffrey R. Olmstead [(11)]	459,096	1.5%	—	—%
Matthew R. Lewis [(11)]	21,039	0.1%	—	—%
Charles L. McLawhorn III [(11)]	10,000	*	—	—%
Sherry L. Morgan [(11)]	22,990	0.1%	—	—%
Peter Adamson III [(11)]	82,685	0.3%	—	—%
C. Fred Ball Jr. [(11)]	91,310	0.3%	—	—%
Peter A. Leidel [(11)]	275,305	0.9%	—	—%
Cameron O. Smith [(11)]	47,340	0.2%	—	—%
Wilkie S. Colyer Jr. [(11)]	4,000	*	—	—%
All named executive officers, directors and director nominees as a group (10 people)	1,754,610	5.8%	—	—%

* Represents less than 0.1% of the outstanding shares of common units

(1) Beneficial ownership for the purposes of this table is defined by Rule 13d-3 under the Exchange Act. Under this rule, a person is generally considered to be the beneficial owner of a security if he has or shares the power to vote or direct the voting thereof or to dispose or direct the disposition thereof or has the right to acquire either of those powers with sixty days.

(2) In August 2016, we issued 11,627,906 Preferred Units. Holders of our Preferred Units may elect to convert into common units representing limited partner interests in our partnership on a one-for-one basis at any time after the six-month anniversary of the closing date, in whole or in part, subject to certain conversion thresholds.

(3) Has a principal business address of 410 Park Avenue, 19th Floor, New York, New York 10022.

(4) Yorktown VI Company, LP is the sole general partner of Yorktown Energy Partners VI, LP. Yorktown VI Associates, LLC is the sole general partner of Yorktown VI Company, LP. As a result, Yorktown VI Associates, LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the common units owned by Yorktown Energy Partners VI, LP. Yorktown VI Company, LP and Yorktown VI Associates, LLC disclaim beneficial ownership of the common units owned by Yorktown Energy Partners VI, LP in excess of their pecuniary interests therein.

(5) Yorktown VII Company, LP is the sole general partner of Yorktown Energy Partners VII, LP. Yorktown VII Associates, LLC is the sole general partner of Yorktown VII Company, LP. As a result, Yorktown VII Associates, LLC may be deemed to have the power to vote or direct the vote or to dispose or direct the disposition of the common units owned by Yorktown Energy Partners VII, LP. Yorktown VII Company, LP and Yorktown VII Associates, LLC disclaim beneficial ownership of the common units owned by Yorktown Energy Partners VII, LP in excess of their pecuniary interests therein.

(6) C/o Mid-Con Energy GP, LLC, 2431 E. 61st Street, Suite 850, Tulsa, Oklahoma 74136.

(7) This disclosure is based on the Schedule 13D filed with the SEC on August 11, 2016 on behalf of each of the following: (i) John C. Goff; (ii) Goff REN Holdings, LLC ("Goff REN"); (iii) Goff MCEP Holdings, LLC ("Goff MCEP Holdings"); (iv) The Goff Family Foundation ("Goff Foundation"); (v) Goff Capital, Inc. ("Goff Capital"); (vi) Longboat Capital, LLC ("Longboat Capital"); (vii) James M. Howard; and (vii) Keith B. Ohnmesis. As of the date of such filing, John C. Goff may be deemed the beneficial owner of (1) 1,860,465 Preferred Units owned by Goff REN, (2) 2,697,674 Preferred Units owned by Goff MCEP Holdings, (3) 232,558 Preferred Units owned by Goff Foundation. As the manager of Goff MCEP Holdings and a member of Goff REN, Goff Capital may be deemed to have the sole power to vote or direct the vote of and the sole power to dispose or direct the disposition of the Preferred Units of Goff MCEP Holdings and the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of the Preferred Units of Goff REN. Goff Capital disclaims beneficial ownership of the Preferred Units of Goff MCEP Holdings and the Preferred Units of Goff REN, except to the extent of its pecuniary interest therein. As the sole board member of Goff Foundation and as president of Goff Capital, John C. Goff may be deemed to have the sole power to vote or direct the vote of and the sole power to dispose or direct the disposition of the Preferred Units of Goff Foundation and the Preferred Units of Goff MCEP Holdings and the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of the Preferred Units of Goff REN. Mr. Goff disclaims beneficial ownership of all of the Preferred Units, except to the extent of its pecuniary interest therein. As a member of Goff REN, Longboat Capital may be deemed to have the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of the Preferred Units of Goff REN. Longboat Capital disclaims beneficial ownership of those Preferred Units, except to the extent of its pecuniary interest therein. As the co-manager of Goff REN, and as manager of Longboat Capital, James M. Howard may be deemed to have the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of the Preferred Units of Goff REN. Mr. Howard disclaims beneficial ownership of those Preferred Units, except to the extent of its pecuniary interest therein. As the co-manager of Goff REN, Keith B. Ohnmeis may be deemed to have the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of the Preferred Units of Goff REN. Mr. Ohnmeis disclaims beneficial ownership of those Preferred Units, except to the extent of its pecuniary interest therein. Mr. Goff has a principal business address of 500 Commerce Street, Suite 700, Fort Worth, Texas 76102.

(8) This disclosure is based on the Schedule 13D filed with the SEC on December 14, 2016 on behalf of each of the following: (i) GAINSCO, Inc. ("GAINSCO"); (ii) SCG Ventures LP ("SCG Ventures"); (iii) FWC Holdings, LLC ("FWC Holdings"); (iv) Stallings Management, LLC ("Stallings Management"); (v) Robert W. Stallings; and (vi) James R. Reis. As of the date of such filing, Mr. Stallings may be deemed the beneficial owner of (1) 1,395,349 Preferred Units owned by GAINSCO (which are also reported as Preferred Units beneficially owned by Mr. Reis in the table above), and (2) 465,116 Preferred Units owned by Stallings Management. As President of Stallings Management and Chairman of the Board of GAINSCO, Robert W. Stallings may be deemed to have the sole power to vote or direct the vote of and the sole power to dispose or direct the disposition of the Preferred Units of SCG Ventures and the common units into which such Preferred Units are convertible and the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of such securities of GAINSCO. Mr. Stallings disclaims beneficial ownership of all of the Preferred Units and the common units into which the Preferred Units are convertible, except to the extent of his pecuniary interest therein. As the general partner of SCG Ventures, Stallings Management may be deemed to have the sole power to vote or direct the vote of and the sole power to dispose or direct the disposition of the Preferred Units of SCG Ventures and the common units into which the Preferred Units are convertible. Stallings Management disclaims beneficial ownership of those securities, except to the extent of its pecuniary interest therein. Mr. Stallings has a principal business address of 3333 Lee Parkway, Suite 1200, Dallas, Texas 75219.

(9) This disclosure is based on the Schedule 13D filed with the SEC on December 14, 2016. As the sole member of FWC Holdings and the Vice Chairman of the Board of GAINSCO, Mr. James R. Reis may be deemed to have the sole power to vote or direct the vote of and the sole power to dispose or direct the disposition of the Preferred Units of FWC Holdings (232,558 Preferred Units) and the common units into which such Preferred Units are convertible and the shared power to vote or direct the vote of and the shared power to dispose or direct the disposition of such securities of GAINSCO (1,395,349 Preferred Units, which are also reported as Preferred Units beneficially owned by Mr. Stallings in the table above). Mr. Reis disclaims beneficial ownership of all of the Preferred Units and the common units into which the Preferred Units are convertible, except to the extent of his pecuniary interest therein. Mr. Reis has a principal business address of 3333 Lee Parkway, Suite 1200, Dallas, Texas 75219.

(10) Has a principal business address of 2651 North Harwood Suite 530, Dallas, Texas 75201.

(11) Has a principal business address of 2431 E. 61st Street, Suite 850, Tulsa, Oklahoma 74136.

The following table sets forth the beneficial ownership of equity interests in our general partner:

Name of Beneficial Owner	Class A Membership Interests	Class B Membership Interests [3]	Total Membership Interests [4]
Charles R. Olmstead [1]	50.00%	—%	33.33%
Jeffrey R. Olmstead [1]	50.00%	—%	33.33%
S. Craig George [2]	—%	100.00%	33.33%

[1] C/o Mid-Con Energy GP, LLC, 2431 E. 61st Street, Suite 850, Tulsa, Oklahoma, 74136.

[2] Has a principal address of 340 Barnside Lane, Eureka, Missouri, 63025.

[3] On January 24, 2017, the members of the general partner, executed the Second Amendment and Restated Limited Liability Company Agreement of Mid-Con Energy GP, LLC (the "Second A/R LLC Agreement"). The Second A/R LLC Agreement was effective January 24, 2017 and created a new class of non-voting membership interests, entitled Class B Membership Interests. Concurrent with his resignation from the Board of Directors of the general partner, Mr. George converted all of his membership interests of the general partner into the new Class B Membership Interests.

[4] Messrs. Olmstead, Olmstead and George, by virtue of their ownership interest in our general partner, may be deemed to beneficially own the interests in us held by our general partner. Each of Messrs. Olmstead, Olmstead and George disclaims beneficial ownership of these securities in excess of his pecuniary interest in such securities.

Securities Authorized for Issuance under Equity Compensation Plan

See the table in "Item 11. Executive Compensation - Long-Term Incentive Program."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

As of December 31, 2016, our general partner has an approximate 1.2% interest in us. The distributions we will make to our general partner are described in Item 5 "Market for Registrant's Common Equity, Related Stockholder Matters and Issue Purchases of Equity Securities."

Agreements and Transactions with Affiliates

The following agreements were negotiated among affiliated parties and, consequently, are not the result of arm's length negotiations. The following is a description of those agreements that have been entered into with the affiliates of our general partner and with our general partner.

Services Agreement

We are party to a services agreement with our affiliate, Mid-Con Energy Operating, pursuant to which Mid-Con Energy Operating provides certain services to us, including management, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. These expenses are included in general and administrative expenses in our consolidated statements of operations. For the year ended December 31, 2016, we paid Mid-Con Energy Operating approximately $3.4 million for expenses pursuant to the services agreement.

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are parties to standard oil and natural gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead associated with operating our properties. We and those third parties also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. The majority of these expenses are included in lease operating expenses in our consolidated statements of operations. For the year ended December 31, 2016, we paid Mid-Con Energy Operating approximately $6.2 million for expenses incurred pursuant to the operating agreements.

Oilfield Services

As discussed above, we are party to operating agreements, pursuant to which our affiliate, Mid-Con Energy Operating, bills us for direct and indirect expenses that are chargeable to the wells, including oilfield services performed by our affiliate, ME3 Oilfield Service. These amounts are included either in lease operating expenses in our consolidated statements of operations or are capitalized as part of oil and natural gas properties in our consolidated balance sheets. For the year ended

December 31, 2016, we paid Mid-Con Energy Operating approximately $3.1 million for oilfield services performed by ME3 Oilfield Service.

Review, Approval or Ratification of Transactions with Related Persons

We have adopted a Code of Business Conduct that sets forth our policies for the review, approval and ratification of transactions with related persons. Pursuant to our Code of Business Conduct, a director is expected to bring to the attention of the Chief Executive Officer or the Board of Directors of our general partner any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our general partner on the other. The resolution of any such conflict or potential conflict will be addressed in accordance with our general partner's organizational documents and the provisions of our partnership agreement. The resolution may be determined by disinterested directors, our general partner's Board of Directors, or the conflicts committee of our general partner's Board of Directors. Our Code of Business Conduct is on our website www.midconenergypartners.com under our corporate governance section.

The Mid-Con Affiliates or other affiliates of our general partner are free to offer properties to us on terms they deem acceptable, and the Board of Directors of our general partner (or the conflicts committee) is free to accept or reject any such offers, negotiating terms it deems acceptable to us. As a result, the Board of Directors of our general partner (or the conflicts committee) will decide, in its sole discretion, the appropriate value of any assets offered to us by affiliates of our general partner. In so doing, we expect the Board of Directors of our general partner (or the conflicts committee) will consider a number of factors in its determination of value, including, without limitation, production and reserve data, operating cost structure, current and projected cash flow, financing costs, the anticipated impact on distributions to our unitholders, production decline profile, commodity price outlook, reserve life, future drilling inventory and the weighting of the expected production between oil and natural gas.

We expect that the Mid-Con Affiliates or other affiliates of our general partner will consider a number of the same factors considered by the Board of Directors of our general partner to determine the proposed purchase price of any assets it may offer to us in future periods. In addition to these factors, given that the Charles R. Olmstead, Jeffrey R. Olmstead and Yorktown are significant unitholders, they may consider the potential positive impact on their underlying investment in us by causing the Mid-Con Affiliates to offer properties to us at attractive purchase prices. Likewise, the affiliates of our general partner may consider the potential negative impact on their underlying investment in us if we are unable to acquire additional assets on favorable terms, including the negotiated purchase price.

Director Independence

NASDAQ Global Select Market does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the Board of Directors of our general partner. For a discussion of the independence of the Board of Directors of our general partner, please see "Item 10. Directors, Executive Officers and Corporate Governance."

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of Mid-Con Energy GP, LLC selected Grant Thornton, LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the years ended December 31, 2016 and 2015. The audit committee's charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit-related, tax and all other fees categories below with respect to this Annual Report on Form 10–K for the year ended December 31, 2016, were approved by the audit committee.

Fees paid to Grant Thornton, LLP are as follows:

	2016	2015
Audit fees	$ 403,000	$ 411,875
Audit-related	—	—
Tax fees	134,911	117,501
Total	$ 537,911	$ 529,376

PART IV

ITEM 15. EXHIBITS

(a)(1) *Exhibits*

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP's registration statement on Form S-1 filed with the SEC on August 12, 2011 (File No.333-176265)).
3.2	Certificate of Formation of Mid-Con Energy GP, LLC (incorporated by reference to Exhibit 3.4 to Mid-Con Energy Partners, LP's registration statement on Form S-1 filed with the SEC on August 12, 2011 (File No. 333-176265)).
3.3	First Amended and Restated Agreement of Limited Partnership of Mid-Con Energy Partners, LP, dated as of December 20, 2011 (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of Mid-Con Energy GP, LLC, dated as of December 20, 2011 (incorporated by reference to Exhibit 3.2 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
3.5	Second Amended and Restated Limited Liability Company Agreement of Mid-Con Energy GP, LLC (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on January 25, 2017).
10.1	Services Agreement, dated as of December 20, 2011, by and among Mid-Con Energy Operating, Inc., Mid-Con Energy GP, LLC, Mid-Con Energy Partners, LP and Mid-Con Energy Properties, LLC (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 23, 2011).
10.2	Credit Agreement, dated as of December 20, 2011, 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 10.2 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.3	Agreement and Amendment No. 1 to Credit Agreement, dated as of April 23, 2012, 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 April 27, 2012).
10.4	Agreement and Amendment No. 2 to Credit Agreement, dated as of November 26, 2012, 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 November 28, 2012).
10.5	Agreement and Amendment No.3 to Credit Agreement, dated as of November 5, 2013, 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 November 6, 2013).
10.6	Amendment No.4 to Credit Agreement, dated as of April 11, 2014, 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 April 15, 2014).
10.7	Agreement and Amendment No.5 to Credit Agreement, dated as of April 11, 2014, 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 April 15, 2014).

10.8	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).
10.9	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).
10.10	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 (incorporated by reference to Exhibit 10.3 to Mid-Con Energy Partners, LP's quarterly report on Form 10-Q filed with the SEC on May 2,2016).
10.11	Amendment No.9 to Credit Agreement, dated as of May 31, 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 (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 June 2, 2016).
10.12	Amendment No.10 to Credit Agreement, dated as of August 11, 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 (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 August 16, 2016).
10.13	Contribution, Conveyance, Assumption and Merger Agreement, by and among Mid-Con Energy GP, LLC, Mid-Con Energy Partners, LP, Mid-Con Energy Properties, LLC, Mid-Con Energy I, LLC, Mid-Con Energy II, LLC and Charles R. Olmstead, S. Craig George, Jeffrey R. Olmstead and other members of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC named therein (incorporated by reference to Exhibit 10.3 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.14	Mid-Con Energy Partners, LP Long-Term Incentive Program (incorporated by reference to Exhibit 4.5 to Mid-Con Energy Partners, LP's Registration Statement on Form S-8 filed with the SEC on January 25, 2012 (File No 333-179161)).
10.15	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 SEC on November 20, 2015).
10.16	Form of Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.17	Class A Convertible Preferred Unit Purchase Agreement, dated as of July 31, 2016, by and among Mid-Con Energy Partners, LP and the Purchasers named on Schedule A thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K file with the SEC on August 3, 2016).
10.18	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and Charles R. Olmstead (incorporated by reference to Exhibit 10.6 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.19	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and Jeffrey R. Olmstead (incorporated by reference to Exhibit 10.7 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.20	Form of Crude Oil Purchase Agreement between Mid-Con Energy Operating, LLC and Enterprise Crude Oil LLC (incorporated by reference to Exhibit 10.10 to Mid-Con Energy LP's annual report on Form 10-K filed with the SEC on March 9, 2012).
10.21	Purchase and Sale Agreement, dated February 28, 2014, by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on March 5, 2014).
10.22	Purchase and Sale Agreement, dated July 24, 2014, by and among Mid-Con Energy III, LLC, Mid-Con Energy Properties, LLC and Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on July 25, 2014).
10.23	Purchase and Sale Agreement, dated October 7, 2014, by and among Mid-Con Energy Properties, LLC, Mid-Con Energy Partners, LP and L.C.S. Production Company, SPA-PETCO, LP, SPA PETCO OSU, LLC, A.G. Hill Oil and Gas LP, and A.G. Hill Oil and Gas II LP (incorporated by reference to Exhibit 2.1 to Mid-Con Energy LP's current report on Form 8-K filed with the SEC on October 14, 2014).

10.24	Purchase and Sale Agreement dated as of May 26, 2016, among Mid-Con Energy Properties, LLC, Mid-Con Energy Operating, LLC as sellers, and PO&G Panhandle, LP, as purchaser thereto (incorporated by reference to Exhibit 10.7 to Mid-Con Energy Partners, LP's quarterly report on Form 10-Q filed with the SEC on August 4, 2016).
10.25	Purchase and Sale Agreement, dated as of July 28, 2016, among Mid-Con Energy Properties, LLC, as purchaser, and Walter Exploration Company, JMW LTD, and Wildcat Properties L.P., as sellers thereto (incorporated by reference to Exhibit 10.8 to Mid-Con Energy Partners, LP's quarterly report on Form 10-Q filed with the SEC on August 4, 2016).
10.26	Form of Phantom Unit Award Agreement (for employees of our Affiliate)(incorporated by reference to Exhibit 10.14 to Mid-Con Energy LP's current report on Form 10-K/A filed with the SEC on June 24, 2014).
21.1	Subsidiaries of Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 21.1 to Mid-Con Energy LP's current report on Form 10-K filed with the SEC on March 9, 2012).
23.1+	Consent of Cawley, Gillespie & Associates, Inc.
23.2+	Consent of Grant Thornton LLP
31.1+	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2+	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1+	Section 1350 Certification of Chief Executive Officer
32.2+	Section 1350 Certification of Chief Financial Officer
99.1+	Cawley, Gillespie & Associates, Inc. Reserve Report
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

Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

+ Filed herewith

++ Furnished herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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
(Registrant)

		By:	Mid-Con Energy GP, LLC, its general partner
Date:	February 28, 2017	By:	*/s/ Matthew R. Lewis*
			Matthew R. Lewis Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2017 .

Signature	Title	Date
/s/ Jeffrey R. Olmstead	Chief Executive Officer and Director	February 28, 2017
Jeffrey R. Olmstead	(Principal Executive Officer)	
/s/ Matthew R. Lewis	Chief Financial Officer	February 28, 2017
Matthew R. Lewis	(Principal Financial Officer)	
/s/ Sherry L. Morgan	Chief Accounting Officer	February 28, 2017
Sherry L. Morgan		
/s/ Charles R. Olmstead	Executive Chairman of the Board	February 28, 2017
Charles R. Olmstead		
/s/ Peter A. Leidel	Director	February 28, 2017
Peter A. Leidel		
/s/ Cameron O. Smith	Director	February 28, 2017
Cameron O. Smith		
/s/ Peter Adamson III	Director	February 28, 2017
Peter Adamson III		
/s/ C. Fred Ball Jr.	Director	February 28, 2017
C. Fred Ball Jr.		
/s/ Wilkie S. Colyer Jr.	Director	February 28, 2017
Wilkie S. Colyer Jr.		

CAWLEY, GILLESPIE & ASSOCIATES, INC.

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CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to our firm, references to Cawley, Gillespie & Associates, Inc. as independent petroleum engineers and to the inclusion of information taken from our reserve audit of Mid-Con Energy Partners, LP as of December 31, 2016 in the Mid-Con Energy Partners, LP Annual Report on Form 10-K for the year ended December 31, 2016, (the “10-K”) and all appendixes, exhibits and attachments thereto filed by Mid-Con Energy Partners, LP. We further consent to the inclusion of our reserve audit dated February 3, 2017 as Exhibit 99.1 in the 10-K.

Sincerely,

Cawley, Gillespie & Assoc., Inc.

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

February 28, 2017
Fort Worth, Texas

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 28, 2017, with respect to the consolidated financial statements included in the Annual Report of Mid-Con Energy Partners, LP on Form 10-K for the year ended December 31, 2016. We consent to the incorporation by reference of said report in the Registration Statements of Mid-Con Energy Partners, LP on Forms S-3 (File No. 333-195669 and File No. 333-187012) and on Forms S-8 (File No. 333-179161 and File No. 333-208203).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 28, 2017

Exhibit 31.1

I, Jeffrey R. Olmstead, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mid-Con Energy Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2017

/s/ Jeffrey R. Olmstead

Jeffrey R. Olmstead
Chief Executive Officer

Exhibit 31.2

I, Matthew R. Lewis, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mid-Con Energy Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2017

/s/ Matthew R. Lewis

Matthew R. Lewis
Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Mid-Con Energy Partners, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2016 , as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Jeffrey R. Olmstead, Chief Executive Officer of the Partnership, certify, pursuant to18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

Date: February 28, 2017

/s/ *Jeffrey R. Olmstead*

Jeffrey R. Olmstead
Chief Executive Officer

Exhibit 32.2

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

In connection with the Annual Report of Mid-Con Energy Partners, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2016 , as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Matthew R. Lewis, Chief Financial Officer of the Partnership, certify, pursuant to18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: February 28, 2017

/s/ Matthew R. Lewis

Matthew R. Lewis
Chief Financial Officer

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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February 3, 2017

Mr. Jeffrey R. Olmstead
Chief Executive Officer
Mid-Con Energy Partners, LP
2431 E. 61 st Street
Tulsa, OK 74136

Re: Reserve Audit

Mid-Con Energy Partners, LP Interests
Total Proved Reserves
As of December 31, 2016

Pursuant to the Guidelines of the
Securities and Exchange Commission for
Reporting Corporate Reserves and
Future Net Revenue

Dear Mr. Olmstead,

At your request, this letter was prepared for Mid-Con Energy Partners, LP ("MCEP") on February 3, 2017 for the purpose of describing our audit of your estimates of proved reserves and forecasts of economics attributable to the subject interests. We examined 100% of MCEP reserves, which are made up of oil and gas properties in various fields in Texas and Oklahoma. This examination utilized an effective date of December 31, 2016, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the Securities and Exchange Commission (SEC). Our examination included all methods and procedures as we considered necessary under the circumstances to render the opinion set forth herein. The estimates as prepared by MCEP are summarized as follows:

	Net Oil (Mbbls)	Net Gas (MMcf)	Net MBOE	Cumulative Cash Flow Disc. @ 10% (M$)
Total Proved	18,210	6,124	19,231	162,141
Proved Developed Producing	10,506	3,726	11,126	107,244
Proved Developed Behind Pipe	505	150	530	5,809
Proved Developed Non-Producing	722	265	767	9,598
Proved Undeveloped	6,477	1,983	6,807	39,490

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its “present worth”. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base. Our audit involved proved reserves only and did not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated.

Hydrocarbon Pricing

The base SEC oil and gas prices calculated for December 31, 2016 were $42.75/bbl and $2.49/MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil and gas prices are based upon WTI-Cushing and Henry Hub spot prices, respectively, as published by the EIA for January 1, 2016 through December 1, 2016.

The base prices shown above were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $40.028 per barrel for oil and $1.988 per MCF for gas. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, severance taxes, lease operating expenses and investments were calculated and prepared by MCEP and were reviewed by us for reasonableness. Lease operating expenses were either determined at the field or individual well level using averages calculated from historical lease operating statements. All economic parameters, including lease operating expenses and investments, were held constant (not escalated) throughout the life of these properties.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages 6 and 7 following this letter. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. Government policies and market conditions different from those employed in this report may cause (1) the total quantity of oil or gas to be recovered, (2) actual production rates, (3) prices received, or (4) operating and capital costs to vary from those presented in this report. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

This evaluation includes 126 proved undeveloped cases in various fields in Texas and Oklahoma but only 74 of these represent new drilled producing wellbores (drilling locations) with the remainder representing additional reserves associated with recompletions, conversions to injectors and water flooding of existing wellbores. Each of these drilling locations proposed as part of MCEP's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, MCEP has indicated they have every intent to complete this development plan within the next five years. Furthermore, MCEP has demonstrated that they have the proper company staffing, financial backing and prior development success to ensure this five year development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described in page 5 following this letter. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. For certain fields either being waterflooded or prepared for a waterflood, proved undeveloped reserves were based upon results from either a pilot waterflood (in the field) or an analogous, nearby waterflood deemed to be relevant. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for MCEP properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this audit.

General Discussion

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have *not* been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. ("CG&A"). Possible environmental liability related to the properties has not been investigated or considered. The cost of plugging and the salvage value of equipment at abandonment have not been included.

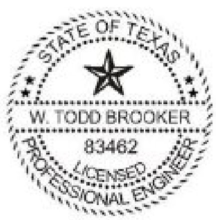
The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

It should be understood that our audit and the development of our reserves forecasts do not constitute a complete reserve study of the oil and gas properties of MCEP. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by MCEP with respect to ownership interests, oil and gas production, historical costs of operation and developments, product prices, agreements relating to current and future operations and sales of production. Furthermore, if in the course of our examination something came to our attention which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data.

Please be advised that, based upon the foregoing, in our opinion the above-described estimates of Mid-Con Energy Partners, LP's total proved reserves are, in the aggregate, reasonable within the established audit tolerance guidelines of (+ or -) 10%. Also, these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers and as mandated by the SEC.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This evaluation was supervised by W. Todd Brooker, Senior Vice President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or Mid-Con Energy Partners, LP and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this audit. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Sincerely,



W. Todd Brooker, P.E.
Senior Vice President
CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm (F-693)

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical anal-yses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increas-ing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the com-plexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric meth-od is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncompli-cated.

Analogy. This method which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for “resource plays,” where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210-.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **Proved oil and gas reserves** . Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations- prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"(i) The area of a reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

"(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

"(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"(6) **Developed oil and gas reserves** . Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

“(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

“(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"(31) **Undeveloped oil and gas reserves** . Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

“(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

“(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

“(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **Probable reserves** . Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

“(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

“(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

“(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

"(17) **Possible reserves** . Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

“(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

“(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

“(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

“(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

“(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

“(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.”

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S-K." This is relevant in that Instruction 2 to paragraph (a)(2) states: “The registrant is *permitted, but not required* , to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item.”

"(26) **Reserves** . Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Note to paragraph (26) : Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."