Mid-Con Energy Partners, LP
Form 10-K
March 13, 2019

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, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File No.: 1-35374

Mid-Con Energy Partners, LP

(Exact name of registrant as specified in its charter)

Delaware	45–2842469
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification 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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). YES NO

Indicate by check mark 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, a smaller reporting company, or an emerging growth company. See definition of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b–2 of the Exchange Act.

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
Emerging Growth Company	

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

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

The aggregate market value of the common units held by non-affiliates of the registrant was $40.4 million on June 30, 2018, based on $1.65 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, 2019, the registrant had 30,658,958 common 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.
Board	The Board of Directors of our general partner.
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.
Class A Preferred Units	Class A Convertible Preferred Units issued on August 11, 2016.
Class B Preferred Units	Class B Convertible Preferred Units issued on January 31, 2018.
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 bore 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 expense and taxes.
EOR	Enhanced oil recovery.
EPA	U.S. Environmental Protection Agency.
Exploratory well	A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.
Extension well	A well drilled to extend the limits of a known reservoir.
FASB	Financial Accounting Standards Board.

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.
G&A	General and administrative expenses.
GHG	Greenhouse gas.
Gross wells	The number of wells in which a working interest is owned.
Injection well	A well employed for the introduction of water, gas or other fluid under pressure into an underground stratum.
LIBOR	London Interbank Offered Rate.
LOE	Lease operating expenses.
MBbls	One thousand Bbls.
MBoe	One thousand Boe.
MBtu	One thousand Btu.
Mboe/d	One thousand Boe per day.

Mcf	One thousand cubic feet.
Mcf/d	One thousand cubic feet per day.
MMBoe	One million Boe.
MMBtu	One million Btu.
MMcf	One million cubic feet.
NASDAQ	National Association of Securities Dealers Automated Quotation System Global Select Market.
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 any 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 and condensate.
Partnership Agreement	First Amended and Restated Agreement of Limited Partnership of Mid-Con Energy Partners, LP, dated as of January 31, 2018, as amended.
Preferred Units	Class A Preferred Units and Class B 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.”
Reserves	Parts of mineral deposits 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 have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas.
Unit	A contiguous geographic area that was established and approved by state oil and natural gas commissions for 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.
WCS	Western Canadian Select, a benchmark in oil pricing.
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 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:

CG&A	Cawley, Gillespie & Associates, Inc., independent third-party petroleum consultants.
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.
ME2 Well Services	refers to ME2 Well Services, LLC, which is an affiliate of our Mid-Con Affiliate and Mid-Con Energy Operating.
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.
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.

CAUTIONARY STATEMENT REGARDING 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. These forward–looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

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

All of these types of statements, other than statements of historical fact included in this Form 10-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 in this 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," "pur "continue," "goal," "forecast," "guidance," "might," "scheduled" and the negative of such terms or other comparable terminolo

The forward-looking statements contained in this 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 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 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 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 under the symbol "MCEP" on the NASDAQ.

Overview

We operate as one business segment engaged in the ownership, acquisition and development of producing oil and natural gas properties. As of December 31, 2018, our properties were located in Oklahoma, Texas and Wyoming core areas. 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. As of December 31, 2018, 60% of our net proved reserves were being produced under waterflood, on a Boe basis. 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. In order to enhance the stability of our cash flow for the benefit of our unitholders, we generally hedge a portion of our production volumes through various commodity derivative contracts.

Our oil and natural gas production and reserve data as of December 31, 2018, were as follows:

- we had total estimated proved reserves of 24.8 MMBoe, of which 96% were oil and 75% were proved developed;
- we owned a working interest in 2,182 wells, 98% operated through our affiliate, Mid-Con Energy Operating;
- average production for the month ended December 31, 2018, was 6,238 gross (3,635 net) Boe/d; and
- our total estimated proved reserves had an average reserve-to-production ratio of 19 years.

Our Business Strategy and Competitive Strengths

Our primary business objective is to create long-term stakeholder value through management of current cash flow and long-term reserves. Our goal is to increase the value of our properties through a combination of waterflood development and efficiently operating long-lived, low-decline, mature properties. The key elements of our strategy are:

- concentrate on competitive strengths;
- pursue acquisitions with the potential to create value through our core strengths;
- maintain and increase long-lived, low-decline reserve base;
- maintain a high degree of operational control and high working interest; and
- optimize cash flow.

These elements are primarily focused on conventional, primarily oil assets in Oklahoma, Texas and Wyoming.

Concentrate on competitive strengths. We focus our attention on assets that have value creation potential through waterflood development and on conventional, primarily oil assets that have complex histories where we can create value through operational enhancements. We have a successful history of economically adding significant production and reserves through waterflooding in Oklahoma and Texas. In 2018, we began acquiring assets in Wyoming where we believe we can continue this track record of adding economic reserves and production through waterflooding. We have also been successful at increasing margins, and consequently value, in conventional, long-lived, low-decline, predominantly oil fields in Oklahoma, Texas and Wyoming.

Pursue acquisitions with the potential to create value through our core strengths. We continue to evaluate fields that we believe have potential for waterflood development or margin enhancements through operational efficiency. These can usually be acquired at relatively low entry costs as the existing margins are relatively low.

Maintain and increase long-lived, low-decline reserve base. Maintaining and increasing a long-lived, low-decline reserve base provides us a more stable platform. This type of asset base requires less reinvestment capital to maintain current production and reserves, leaving more free cash flow to be deployed in growth projects and/or acquisitions.

Maintain a high degree of operational control and high working interest. We are able to have a high degree of operational control by operating a high percentage of our properties through our affiliate, Mid-Con Energy Operating. Our operational control along with maintaining a high working interest in our assets allows us to control our operating costs and the timing of our capital expenditures.

Optimize cash flow. We are focused on maximizing the value and cash flow generated from our operations by increasing reserves and production while controlling costs. Our approach to managing our properties provides us the ability to react quickly to changing commodity price environments. As commodity prices fall, we are able to shut in our lowest margin wells to lessen the impact on cash flow. Since the vast majority of our production is unitized, we are able to shut-in marginal wells without forfeiting leasehold. As oil prices rise, we are able to return wells to operation, increasing the impact on cash flow. Our cash flow optimization allows us to optimize the timing and allocation of capital among our investment opportunities to maximize the rates of return on our properties. We exercise financial discipline by attempting to balance our development capital expenditures with our cash flows from our operations.

Our Areas of Operations

As of December 31, 2018, our properties were primarily located in the Mid-Continent, Permian, Big Horn and Powder River Basin regions of the United States in the Oklahoma, Texas and Wyoming core areas. These core areas are generally composed of multiple fields and 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.

Oklahoma

The majority of our Oklahoma properties are being produced under waterflood and are operated by Mid-Con Energy Operating. At December 31, 2018, our average working interest in these properties was 89%. During 2018, we drilled 4 gross producing wells and converted 4 gross wells to injection.

Texas

At December 31, 2018, we had an average working interest of 95% in our Texas properties. During 2018, we drilled 5 gross producing wells, 1 gross injection well and converted 4 gross wells to injection wells.

Wyoming

At December 31, 2018, we had an average working interest of 80% in our Wyoming properties.

The following table shows our estimated net proved reserves by core area, based on a reserve report prepared by our internal reserve engineers and audited by CG&A, our independent petroleum engineers, as of December 31, 2018:

Estimated Net Proved Reserves as of December 31, 2018			
% of		% Proved	Standardized Measure

Core Area	MBoe	Total Proved Reserves	% Oil	Developed Reserves	Amount [1] ($ in millions)	% of Total
Oklahoma	13,198	53 %	95 %	88 %	$ 163	47 %
Texas	4,215	17 %	95 %	88 %	$ 84	24 %
Wyoming	7,429	30 %	98 %	45 %	$ 101	29 %
Total	24,842	100 %	96 %	75 %	$ 348	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 $65.56 per Bbl for oil and $3.10 per MMBtu for natural gas for the 12 months ended December 31, 2018.

Drilling Activities

The following table sets forth information with respect to drilling activities during the periods indicated. The information should not be considered indicative of future performance nor should a correlation be assumed between the numbers of productive wells drilled, quantities of reserves found or economic value. We did not drill any exploratory wells in 2018 or 2017.

	Year Ended December 31,			
	2018		2017	
	Gross	Net	Gross	Net
Developmental wells:				
Productive	9	9	14	13
Injection	1	1	3	3
Water Supply	—	—	1	1
Dry	—	—	1	1
Total	10	10	19	18

Oil and Natural Gas Production, Production Prices and Production Costs

The following table sets forth summary information regarding our historical production and operating data for the years ended December 31, 2018 and 2017. Due to normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production and Unit Costs per Boe

The following table provides net production volume data and average unit costs per Boe:

	Year Ended December 31,	
	2018	2017
Production Volumes		
Oil (MBbls)	1,112	1,209
Natural gas (MMcf)	457	431
Total (MBoe)	1,188	1,281
Average daily net production (Boe/d)	3,255	3,510
Average sales price		
Oil (per Bbl)		
Sales price	$58.64	$47.72
Effect of net settlements on matured derivative instruments[1]	$(6.59)	$(3.64)
Realized oil price after derivatives	$52.05	$44.08
Natural gas (per Mcf)	$2.47	$2.88
Average unit costs per Boe		
Lease operating expenses	$18.97	$16.24

Production and ad valorem taxes	$4.62	$3.22
Depreciation, depletion and amortization	$14.10	$13.83
General and administrative expenses	$5.31	$4.46

(1) For the year ended December 31, 2017, effect of net settlements on matured derivative instruments does not include the $0.6 million received and the $1.1 million of deferred premiums paid upon early termination of previous oil derivative contracts in September and October 2017.

Production

The following table sets forth our production by core area for the years ended December 31, 2018 and 2017:

	Year Ended December 31,			
	2018		2017	
Core Area	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Oklahoma	507	178	686	159
Cleveland Field[(1)]	210	2	240	—
Creek County (Oilton)[(1)]	128	115	132	128
Texas	448	167	523	272
Wyoming	157	112	—	—
Total	1,112	457	1,209	431

[(1)] Oklahoma includes production for the Cleveland and Creek County Fields, which are the only fields that represented 15% or more of our total estimated proved reserves at December 31, 2018 and 2017.

Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2018. 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.

	Productive Wells			
	Oklahoma	Texas	Wyoming	Total
Gross				
Oil	686	183	412	1,281
Natural Gas	13	—	—	13
Total Gross Wells	699	183	412	1,294
Net				
Oil	610	173	321	1,104
Natural Gas	8	—	—	8
Total Net Wells	618	173	321	1,112

Operations

General

We operate 98% of our properties, as calculated on a Boe basis as of December 31, 2018, through our affiliate, Mid-Con Energy Operating. For all of the wells we operate, we design and manage the development, recompletion or workover procedures and supervise operational 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 and affiliates 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, a description of the services 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.

Engineering, Geological and Other Technical 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 approximately 20 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 Related Parties” 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 Related Parties.”

Oil and Natural Gas Leases

The typical oil and natural gas 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. As of December 31, 2018, the lessor royalties and other leasehold burdens on our properties ranged from less than 11.9% to 32.2%, resulting in a net revenue interest to us ranging from 67.8% to 88.1% on a 100% working interest basis, and our average net revenue interest is 71.6%. For the majority of our properties, leases are held by production and do not require lease rental payments.

Principal Customers

For the year ended December 31, 2018, sales of oil and natural gas to three purchasers accounted for 83% of our sales. The loss of any of our customers could temporarily delay production and sales 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.

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.

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, 2018, our commodity derivative contracts had maturities through September 2020 and were comprised of commodity price and differential swaps. 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.”

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 U.S. onshore oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which have delayed development drilling 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 program.

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 officer's 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 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.

Prior to the current U.S. Presidential administration, the clear trend in environmental regulation has been 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. 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 U.S. waters 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 U.S. waters. 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 ("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 oil and/or natural gas 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 related to this regulatory authority. In addition, from time to time, 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 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 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 deep well 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. 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 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 oil and natural gas wells that are being drilled throughout the United States. 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.

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 (“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, in May 2016, the EPA issued new regulations that set methane and VOC emission standards for certain oil and natural gas facilities. In July 2017, the EPA proposed a two-year study of certain requirements of this rule pending reconsideration of the rule. The Paris Agreement, which was created by the United Nations Framework Convention on Climate Change, entered into force 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. The United States announced its intention to withdraw from the Paris Agreement on June 1, 2017.

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 also previously 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 was stayed pending judicial review, and in October 2017, the EPA proposed the repeal of the Clean Power Plan. Legal challenges caused delays to repeal the regulations. However, the U.S. Supreme Court rejected any further court challenges to the Trump Administration's decision to repeal the Clean Power Plan in October 2018.

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 the 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. 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. 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.

There are constantly 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.

Regulation of Oil and Gas Pipelines

Oil and gas pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation ("DOT") and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") under the DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016," which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

The PHMSA has proposed additional regulations for gas pipeline safety. For example, in March 2016, the PHMSA proposed a rule that would expand integrity management requirements beyond "High Consequence Areas" to apply to gas pipelines in newly defined "Moderate Consequence Areas." Also, on January 10, 2017, the PHMSA approved final rules expanding its safety regulations for hazardous liquid pipelines by, among other things, expanding the required use of leak detection systems, requiring more frequent testing for corrosion and other flaws and requiring companies to inspect pipelines in areas affected by extreme weather or natural disasters. The final rule was withdrawn by the PHMSA in January 2017, and it is unclear whether and to what extent the PHMSA will move forward with its regulatory reforms.

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 approximately 100 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, and Gillette, Wyoming. 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. 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, the Board elected to suspend quarterly cash distributions on our common units and the terms of our revolving credit facility require the pre-approval of our lenders before we resume making distributions. The Board may not elect to resume the quarterly distributions on our common units, but if they do, we may not have sufficient cash available to continue to make quarterly distributions on our common 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.

Our Partnership Agreement also prevents us from declaring or making any distributions on our common units if we fail to pay any Class A Preferred Unit or Class B Preferred Unit distribution in full on the applicable payment date, until such time as all accrued and unpaid Class A Preferred Unit and Class B Preferred Unit distributions have been paid in full in cash.

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

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

At the quarter ended September 30, 2017, we were not in compliance with our leverage calculation ratio. Although we subsequently received a waiver from the Administrative Agent and the Lenders under our revolving credit facility and are now in compliance with the leverage calculation ratio, there can be no assurances that we will remain in compliance with the leverage calculation ratio or any other ratios in the future, or that we will receive another waiver should we fail to satisfy a covenant again.

Our debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

Our existing and future indebtedness could have important consequences to us and our business, including but not limited to the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on terms acceptable to us;
- we may need to apply a substantial portion of our cash flow toward principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results and cash flows are not sufficient to service our current or future indebtedness, in addition to the suspension of distributions, we will be forced to take actions such as further reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

If oil prices decline from current levels, 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.

Historically, oil prices have been extremely volatile. For the five years ended December 31, 2018, front-month NYMEX-WTI oil futures prices ranged from a high of $107.26 per barrel to a low of $26.21 per barrel. The volatility of the energy markets makes it extremely difficult to predict future oil price movements with any certainty.

Lower oil prices may decrease our revenues and therefore, our cash flows from operations. 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, include:

- 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 adversely affect our cash flows from operations and 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, the Board 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.

If commodity prices decline from current levels, production from some of our producing or development projects may become uneconomic and cause write downs of the value of our properties, which may adversely affect our ability to borrow, our financial condition and our ability to make distributions to our unitholders.

If commodity prices decline from current levels, some of our producing or development projects may become uneconomic and, if the decline is severe or prolonged, a significant portion of such projects may become uneconomic. As producing or development projects become uneconomic, our reserve estimates will be adjusted downward, which could negatively impact our borrowing base under our current revolving credit facility and our ability to fund our operations.

Deteriorating commodity prices may cause us to recognize impairments in the value of our oil and natural gas properties. We recognized $31.2 million in non-cash impairment expense for the year ended December 31, 2018. 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 adversely affect our financial condition.

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 flows from operations.

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 adversely impact our liquidity, financial condition and cash flows from operations.

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 or other proposed 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.

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 from operations and ability to resume making distributions on our common units are highly dependent on our success in economically finding or acquiring recoverable reserves and efficiently developing 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.

Our business requires significant capital expenditures, and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

We make, and expect to continue to make, substantial capital expenditures for the development, production and acquisition of oil and natural gas reserves. We do not expect to fund all of these expenditures with cash flows from operations and, if additional capital is needed, we may not be able to obtain debt or equity financing on attractive terms or at all, due to lower oil and natural gas prices, declines in our estimated reserves or production or for any other reason. If cash generated by operations or availability 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.

Developing and producing oil and natural gas is a costly and high-risk activity with many uncertainties that could adversely affect our business activities, financial condition or results of operations.

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 financial condition or results of operations.

We inject water into most of our properties to maintain and, in some instances, to increase the production of oil and natural gas. In the future we may 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 cleanup 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 natural gas 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 2018 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 $348.3 million to $259.2 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.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil reserves. We may not achieve the expected results of any acquisition we complete, and any adverse conditions or developments related to any such acquisition may have a negative impact on our operations and financial condition. 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 could 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, Texas and Wyoming. An adverse development in the oil and natural gas business in these geographic areas could have an impact on our business, financial condition and results of operations.

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 sales 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 three purchasers accounted for 83% of our sales for the year ended December 31, 2018. 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 flows from operations could decline which could adversely affect our financial condition and results of operations.

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 delay or prevent us from developing certain properties or greatly increase the cost of their development.

Typical regulatory requirements for waterflood unit formation require anywhere from 63% to 85% of the owners (leasehold, mineral and others) in a proposed unit area to consent to a unitization plan before the relevant regulatory body 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 and federal regulatory agencies. 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 business activities, financial condition and results of operations.

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 a 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.

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, which 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 develop our reserves.

Our revolving credit facility has restrictions and financial covenants that may restrict our business and financing activities, and the pre-approval of our lenders will be required for us to resume distributions on our common units.

Our revolving credit facility also 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. Further, the terms of our credit agreement require the pre-approval of our lenders in order to reinstate distributions on our common units.

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. In May 2016, the EPA issued new regulations that set methane and VOC emission standards for certain oil and natural gas facilities. In July 2017, the EPA proposed a two-year stay of certain requirements of this rule pending reconsideration of the rule. In addition, under the Paris Agreement, which went into effect on November 4, 2016, the United States is required to establish increasingly stringent nationally determined contributions to mitigate climate change. The United States announced its intention to withdraw from the Paris Agreement on June 1, 2017. 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. In addition, we are currently defending against certain third-party lawsuits and could be subject to additional claims, seeking alleged property damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Rules 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 rules became effective October 15, 2012; however, a number of the requirements did not take immediate effect as the final rule established 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. 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.

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 and natural gas 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 guidance documents related to this regulatory authority. In addition, from time to time, Congress has considered legislation 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. 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. More recently, there have been reports linking the injection of produced fluids from hydraulic fracturing to earthquakes, which have resulted in claims of liability against producers. 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, and could adversely affect our financial condition and results of operations.

A failure in our operational systems or cybersecurity 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 cybersecurity attacks that affect our facilities, vendors, customers or 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, cybersecurity 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 cybersecurity 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 cybersecurity attacks.

Risks Inherent in an Investment in Us

Our general partner controls us, and the voting members of our general partner, our Mid-Con Affiliate and Yorktown own an approximate 17% 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, 2018, the voting members of our general partner, our Mid-Con Affiliate and Yorktown own an approximate 17% interest in us. Although our general partner has a duty to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a 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, replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its 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 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 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 affect our business, results of operations, cash flows from operations and financial condition, and cause a decline in the demand for yield-based equity investments such as our common units and the Preferred Units.

All of the indebtedness outstanding under our revolving credit facility is at variable interest rates; therefore, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates. Further, an increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for equity investments such as our common units. Any reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

Our Preferred Units rank senior in right of payment to our common units, and we are unable to make any distributions to our common unitholders unless full cumulative distributions are made on our Preferred Units.

Our Preferred Units 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, and other restrictions associated with, the Preferred Units could impact our liquidity and our ability to finance future operations.

Our obligation to pay distributions on 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) amendment of 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 our existing credit facility or trade payables arising in the ordinary course of business) or (v) the lifting of 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.

The holders of our Preferred Units are entitled to convert their Preferred Units or cause us to redeem them, which could dilute the holders of our common units or require us to raise cash to fund a redemption.

The holders of our Preferred Units may convert the Preferred Units into common units on a one-for-one basis, in whole or in part, subject to certain conversion thresholds. At any time after August 11, 2021, each holder of the Preferred Units shall have the right to cause us to redeem all or any portion of the outstanding Preferred Units for cash. In addition, in connection with a change of control of the Partnership, holders of Preferred Units may elect to have their Preferred Units converted into common units, plus accrued but unpaid distributions to the conversion date, and if holders of Preferred Units do not elect to convert all of their Preferred Units, then, unless the Partnership is the surviving entity of the change of control, we must 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. In addition, if we are required to redeem outstanding Preferred Units, it would result in a significant cash expenditure and, if we did not have sufficient funds on hand at that time, we would have to incur borrowings or otherwise finance the cost of such redemption.

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 U.S. 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 U.S. laws 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, 2018, the voting members of our general partner, our Mid-Con Affiliate and Yorktown own an approximate 17% 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 interests 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 voting members of our general partner 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, including additional preferred units. 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 voting rights of unitholders owning 20% or more of our common units, other than our general partner and its affiliates, the holders of our Preferred Units and Yorktown, which may limit the ability of significant common unitholders to influence the manner or direction of management.

Our Partnership Agreement restricts unitholders' 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 our general partner and its affiliates, the holders of our Preferred Units, Yorktown and 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, 2018, the voting members of our general partner, our Mid-Con Affiliate and Yorktown own 5,198,909 common units and 360,000 units held by our general partner, or an approximate 18% 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.

Although we have suspended distributions on our common units, 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. This requirement could apply to quarterly distributions made before suspension and to future distributions, in the event we elect to reinstate the distributions. 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.

We are a master limited partnership ("MLP"). Volatile market conditions and widespread distribution suspensions have changed investor appetite and resulted in a decrease in demand for debt and equity securities issued by MLPs engaged in the upstream oil and gas business ("Upstream MLPs"). This may affect our ability to access the equity and debt capital markets.

The volatility in energy prices and widespread suspension of distributions, among other factors, has contributed to a dislocation in the pricing of debt and equity securities issued by Upstream MLPs, and a number of Upstream MLPs have been adversely affected by this environment. The elimination of distributions to limited partners has caused many investors to discontinue their interest in investing in debt and equity securities issued by Upstream MLPs. While we intend to finance our future capital expenditures with cash flow from operations and, subject to availability, borrowings under our revolving credit facility, we may need or desire to rely on our ability to raise capital in the equity and debt markets to add reserves and to refinance our debt. Continued volatility and lack of investor demand may affect our ability to access capital markets to finance our growth or refinance our debt in our current legal structure and tax status.

We may not be able to maintain our listing on the NASDAQ Global Select Market.

NASDAQ has established certain standards for the continued listing of a security on the NASDAQ Global Select market. The standards for continued listing include, among other things, that the minimum bid price for the listed securities not fall below $1.00 per share for a period of 30 consecutive trading days. In the future we may not satisfy the NASDAQ's continued listing standards. If we do not satisfy any of the NASDAQ's continued listing standards, our units could be delisted. Any such delisting could adversely affect the market liquidity of our units and the market price of our units could decrease. A delisting could adversely affect our ability to obtain financing for our operations or result in a loss of confidence by investors, customers, suppliers or employees.

Tax Risks to Unitholders

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.

In October 2015, our Board elected to suspend quarterly cash distributions on our common units. 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. Additionally, we may engage in transactions to de-lever the Partnership and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, unitholders may be allocated taxable income or gain resulting from the sale without receiving a cash distribution.

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 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 or an investment in our units. Additionally, final Treasury Regulations under Section 7704(d)(1)(E) of the Internal Revenue Code of 1986, as amended (the "Code"), interpret the scope of qualifying income for publicly traded partnerships by providing industry-specific guidance. We believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the current law and the final Treasury Regulations.

In addition, the Tax Cuts and Jobs Act (the "TCJA") enacted December 22, 2017, made significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the tax rate on an individual or other non-corporate unitholder's allocable share of certain income from a publicly traded partnership. The TCJA is complex and lacks administrative guidance implementing certain of its provisions, thus, the impact of certain aspects of its provisions on us or an investment in our units is currently unclear. Unitholders should consult their tax advisor regarding the TCJA and its effect on an investment in our units.

Any changes to the U.S. federal income tax laws and interpretations thereof (including administrative guidance relating to the TCJA) 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 or otherwise adversely affect us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes or interpretations thereof could negatively impact the value of an investment in our units.

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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our general partner and unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

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.

Unitholders may be subject to limitations on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the TCJA, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income plus 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to, among other items, any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, depletion or amortization. Any interest disallowed may be carried forward and deducted in future years by the unitholder from their share of our "excess taxable income," which is generally equal to the excess of 30% of our adjusted taxable income over the amount of our deduction for business interest for such future taxable year, subject to certain restrictions.

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. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including, with certain exceptions, by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities and non-U.S. persons should consult a tax advisor before investing in our units.

We may be required to deduct and withhold amounts from distributions to non-U.S. unitholders related to withholding tax obligations arising from the sale or disposition of our units by non-U.S. unitholders.

Under the TCJA, effective for sales, exchanges or other dispositions after December 31, 2017, transferees are generally required to withhold 10% of the amount realized on the sale, exchange or other disposition of a unit by a non-U.S. unitholder if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. If the transferee fails to satisfy this withholding requirement, we will be required to deduct and withhold such amount (plus interest) from future distributions to the transferee. Because of complications arising from this withholding requirement, including, by way of example, our inability to match transferors and transferees of units, the Department of the Treasury and the IRS have currently suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our units, pending promulgation of implementing regulations or other guidance. It is unclear when such regulations or other guidance will be issued.

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 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 the subject of a securities loan (e.g. a loan 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 there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan 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 and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any items 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 securities loan 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 and loaning 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.

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, foreign, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Oil and Natural Gas Reserves

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 the estimates to be in compliance with the SEC rules, regulations, definitions and guidance. Our proved reserves are estimated at the well, lease 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, LOE, product pricing, production and ad valorem 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, President. Mr. Brooker has been a Petroleum Consultant for CG&A since 1992, became Senior Vice President in 2011 and President in 2017. 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.

The Vice President of Development of Mid-Con Energy Operating, Chad B. Roller, Ph.D., is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Dr. Roller 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 and Master of Science and Bachelor of Science degrees from the University of Oklahoma.

Estimated Proved Reserves

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2018, 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	17,634	6,059	18,643
Estimated proved undeveloped reserves	6,155	262	6,199
Total	23,789	6,321	24,842

(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 $65.56 per Bbl for oil and $3.10 per MMBtu for natural gas at December 31, 2018. 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 $62.17 per Bbl of oil and $2.43 per Mcf of natural gas.

The data in the table above represents 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 and natural gas 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.

Development of Proved Undeveloped Reserves

With respect to PUDs, we have established a development plan approved by the Vice President of Development of Mid-Con Energy Operating that is expected to result in converting the PUDs to proved developed reserves within five years from the initial disclosure of the reserves. Additionally, 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. None of our proved undeveloped reserves as of December 31, 2018, had remained undeveloped for more than five years from the date the reserves were initially booked as proved undeveloped.

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, 2018, were 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 2018, our capital expenditures totaled $8.6 million, of which $4.5 million was for development (drilling, recompletion and conversion to injection). Based on our current cash flow projections, we expect to fund our 2019 capital spending program of approximately $10.9 million with cash flows from operations, including approximately $9.9 million for the development of PUD reserves. 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."

The following table summarizes the changes in our PUDs during the year ended December 31, 2018:

	Net Oil MBbls	Net Gas MMcf	Total Net MBoe
Proved undeveloped reserves as of December 31, 2017	4,998	1,696	5,281
Conversion to proved developed reserves	(1,019)	(112)	(1,037)
Revisions of previous estimates[1]	1	(1,274)	(212)
Purchases of proved undeveloped reserves	2,185	—	2,185
Extensions and discoveries of proved undeveloped reserves	24	—	24
Sales of proved undeveloped reserves	(34)	(48)	(42)
Reduction due to aged five or more years	—	—	—
Proved undeveloped reserves as of December 31, 2018	6,155	262	6,199

[1] Revisions of previous estimates represent changes in the previous reserves estimates, either upward or downward, resulting from changes in our previously adopted development plans, or 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.

For the year ended December 31, 2018, our PUDs increased from 5,281 MBoe to 6,199 MBoe. The change was primarily attributable to:

Conversion to proved developed reserves. We converted 1,037 MBoe from PUDs to proved developed reserves.

Revisions of previous estimates. Revisions of prior estimates of 212 MBoe resulted from a net decrease of 301 MBoe, offset by positive revisions of 89 MBoe due to price increases. Commodity prices improved in 2018. The 12-month average price for crude oil increased 28% from $51.34 per Bbl for 2017 compared to $65.56 per Bbl for 2018, while the 12-month average price for natural gas increased 4% from $2.98 per MMBtu for 2017 compared to $3.10 per MMBtu for 2018.

Purchases of proved undeveloped reserves. Multiple acquisitions in Wyoming throughout 2018 resulted in a positive increase of 2,185 MBoe in PUDs.

Extensions and discoveries of proved undeveloped reserves. These were additions to PUDs that resulted from successful offset drilling in our Texas core area during the year ended December 31, 2018.

Sales of proved undeveloped reserves. The divestiture of several small properties in Texas resulted in a decrease in PUDs of 42 MBoe.

Developed and Undeveloped Acreage

The following table sets forth information relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests were excluded from this table. As of December 31, 2018, 99% of our leasehold acreage was held by production:

	Developed Acreage	Undeveloped Acreage

Core Area	Gross	Net	Gross	Net
Oklahoma	61,469	35,486	—	—
Texas	19,315	18,186	1,410	1,400
Wyoming	126,128	102,697	—	—
Total	206,912	156,369	1,410	1,400

Drilling Activities

For information with respect to wells drilled and completed for the years ended December 31, 2018 and 2017, see Item 1. “Business - Drilling Activities.”

Productive Wells

For information with respect to the number of productive oil and natural gas wells on our properties for the years ended December 31, 2018 and 2017, see Item 1. “Business - Productive Wells.”

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.

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.

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 under the symbol “MCEP” on the NASDAQ. At the close of business on February 19, 2019, based upon information received from our transfer agent and brokers and nominees, we had 38 limited partner unitholders of record. This number does not include owners for whom common units may be held in “street” names.

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. Management and the Board will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining any 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 regarding equity.

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, 2018.

Sales of Unregistered Securities

During the first quarter of 2018, we issued $15.0 million of Class B Preferred Units. See Note 10 to the Consolidated Financial Statements included in Item 8. “Financial Statements and Supplementary Data” for additional information. The Class B 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

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

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

As of December 31, 2018, our total estimated proved reserves were 24.8 MMBoe, of which 96% were oil and 75% were proved developed, both on a Boe basis. As of December 31, 2018, we operated 98% of our properties through our affiliate, Mid-Con Energy Operating, and 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, 2018, was 3,635 Boe/d and our total estimated proved reserves had a reserve-to-production ratio of 19 years.

2018 Highlights

The fiscal year ended December 31, 2018, was a transformative year for the Partnership. We significantly improved our financial position and closed multiple acquisitions, expanding our new core area of Wyoming and our footprint in Oklahoma. Highlights for the year included:

- extended maturity of our revolving credit facility to November 2020;
- increased borrowing base of our revolving credit facility by $20.0 million;
- decreased total revolving credit facility borrowings by $6.0 million;
- decreased total leverage, as calculated by our revolving credit agreement (3.17X as of the quarter ended December 31, 2018, compared to 3.54X as of the quarter ended December 31, 2017);
- issued $15.0 million in preferred equity;
- closed acquisitions of approximately $23.0 million, after post-closing adjustments, in Oklahoma and Wyoming; and
- increased production 31% (3,663 Boe/d for the fourth quarter of 2018 compared to 2,800 Boe/d in first quarter 2018).

Recent Developments

Strategic Transaction

On February 19, 2019, we announced that we had entered into definitive agreements to sell substantially all of our Texas assets for $60.0 million and to acquire producing properties in Caddo, Grady and Osage counties, Oklahoma for $27.5 million, both subject to customary purchase price adjustments. These agreements are conditioned to close simultaneously on, or about, March 28, 2019, with an effective date the same as the closing date, and we plan to use the net proceeds from this transaction to reduce outstanding borrowings on our revolving credit facility. This transaction is expected to strengthen our financial position and lower our base PDP decline rate, requiring less reinvestment capital to maintain current production and reserves, and creating more free cash flow for deployment in growth projects and/or acquisitions.

Capital Budget

Our 2019 capital budget will be focused on evaluating development opportunities in many of these new assets, while also continuing to develop our existing waterfloods. We will also be focused on operational enhancements in many of the newly acquired fields with expectations of increasing the margins and the value of reserves. We expect to continue acquiring properties with significant waterflood development opportunities, as well as properties with existing low margins where the opportunity exists to enhance these margins through our competitive strengths.

Revolving Credit Facility

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

Distributions

A cash distribution of $0.0430 per Class A Preferred Unit, or $0.5 million in aggregate, and a cash distribution of $0.0306 per Class B Preferred Unit, or $0.3 million in aggregate, was paid on February 14, 2019, to holders of record as of the close of business on February 7, 2019.

Appointment and Departure of Certain Officers and Directors

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

On January 17, 2019, Mr. Peter Adamson, III, a Director of the general partner and Chairman of the Audit Committee, passed away. As a result, the Board elected Mr. Charles Frederick Ball, Jr. as Chairman of the Audit Committee on January 21, 2019.

Business Environment

The markets for oil and natural gas have been volatile and may continue to be volatile in the future, which means that the price of oil and natural gas may fluctuate widely. Sustained periods of low prices for oil and natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. Our average sales price per barrel of oil, excluding commodity derivative contracts, was $58.64 and $47.72 for the years ended December 31, 2018 and 2017, respectively.

The following table is a summary of NYMEX-WTI futures prices for the years ended December 31, 2018 and 2017:

	Price Range		
	High	Low	Average
2018	$76.41	$42.53	$ 64.90
2017	$60.42	$42.53	$ 50.85

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (commodity price and differential swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent or as required by our lenders. We conduct our risk management activities exclusively with participant lenders in our revolving credit facility. We have entered oil commodity derivative contracts covering a portion of our anticipated oil production through December 2021 as of February 28, 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 development projects and acquisitions is dependent upon many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and close acquisitions.

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

How We Evaluate Our Operations

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating stable cash flows, which will provide stability and, over time, growth of distributions to our unitholders. The amount of cash that we 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; and
- LOE.

Results of Operations

The tables presented in this section summarize certain of the results of operations and period-to-period comparisons for the years ended December 31, 2018 and 2017. Because of normal production declines, changes in drilling activities, fluctuations in commodity prices and the effects of acquisitions and divestitures, the historical data presented below should not be interpreted as being indicative of future results.

Production and Unit Costs per Boe. The table below provides production volume data, average sales price and average unit costs per Boe:

	Year Ended December 31,			
	2018	2017	Change	% Change
Production Volumes				
Oil (MBbls)	1,112	1,209	(97)	(8%)
Natural gas (MMcf)	457	431	26	6%
Total (MBoe)	1,188	1,281	(93)	(7%)
Average daily net production (Boe/d)	3,255	3,510	(255)	(7%)
Average sales price				
Oil (per Bbl)				
Sales price	$58.64	$47.72	$10.92	23%
Effect of net settlements on matured derivative instruments[1]	$(6.59)	$(3.64)	$(2.95)	(81%)
Realized oil price after derivatives	$52.05	$44.08	$7.97	18%
Natural gas (per Mcf)	$2.47	$2.88	$(0.41)	(14%)
Average unit costs per Boe				
Lease operating expenses	$18.97	$16.24	$2.73	17%
Production and ad valorem taxes	$4.62	$3.22	$1.40	43%
Depreciation, depletion and amortization	$14.10	$13.83	$0.27	2%
General and administrative expenses	$5.31	$4.46	$0.85	19%

[1] For the year ended December 31, 2017, effect of net settlements on matured derivative instruments does not include the $0.6 million received and the $1.1 million of deferred premiums paid upon early termination of previous oil derivative contracts in September and October 2017.

Oil and natural gas sales. The following table provides oil and natural gas sales data for the years ended December 31, 2018 and 2017:

	Year Ended December 31,			
(in thousands)	2018	2017	Change	% Change
Oil sales	$65,206	$57,689	$7,517	13%
Natural gas sales	1,130	1,240	(110)	(9%)
Total oil and natural gas sales	$66,336	$58,929	$7,407	13%

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

(in thousands, except prices)

	Change in prices	Production Volumes	Total Net Dollar Effect of Change
Effects of changes in sales price			
Oil (Bbls)	$ 10.92	1,112	$12,143
Natural gas (Mcf)	$ (0.41)	457	(185)
Total oil and natural gas sales due to change in price			11,958

	Change in Production Volumes	Prior Period Average Prices	Total Net Dollar Effect of Change
Effects of production volumes			
Oil (Bbls)	(97)	$ 47.72	$(4,626)
Natural gas (Mcf)	26	$ 2.88	75
Total oil and natural gas sales due to change in production volumes			(4,551)
Total change in oil and natural gas sales			$7,407

The change in oil and natural gas sales was primarily due to:

- increased oil sales prices; and

- incremental production from the Oklahoma and Wyoming acquisition properties, offset by the divestiture of our Southern Oklahoma properties.

Gain (loss) on derivatives, net. The table below summarizes the cash and non-cash components of our commodity derivative contracts as well as the change for the years ended December 31, 2018 and 2017:

	Year Ended December 31,			
(in thousands)	2018	2017	Change	% Change
Cash settlements on matured derivatives[1]	$(6,928)	$(369)	$(6,559)	(1778 %)
Cash settlements on early terminations of derivatives[1]	—	582	(582)	(100 %)
Non-cash change in fair value of derivatives	12,602	(2,158)	14,760	684 %
Total gain (loss) on derivatives, net	$5,674	$(1,945)	$7,619	392 %

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

Lease operating expenses. The following table summarizes the change in lease operating expenses for the years ended December 31, 2018 and 2017:

	Year Ended December 31,			
(in thousands)	2018	2017	Change	% Change
Lease operating expenses	$21,374	$20,310	$1,064	5 %
Workover expenses	1,163	495	668	135 %
Total lease operating expenses	$22,537	$20,805	$1,732	8 %

The change in lease operating expenses was primarily due to:

- incremental costs associated with properties acquired in Oklahoma and Wyoming;
- increased workovers at properties acquired in Oklahoma and Wyoming and on certain Texas properties;
- decreased spending on Texas properties; and
- divestiture of our Southern Oklahoma properties.

The following table summarizes lease operating expenses per Boe data for the years ended December 31, 2018 and 2017:

	Year Ended December 31,			
(per Boe)	2018	2017	Change	% Change
Lease operating expenses	$17.99	$15.85	$ 2.14	14 %
Workover expenses	0.98	0.39	0.59	151 %
Total lease operating expenses per Boe	$18.97	$16.24	$ 2.73	17 %

The change in lease operating expenses per Boe was primarily due to the changes noted above and decreased production volumes.

Production and ad valorem taxes. The following table summarizes the change in production and ad valorem taxes for the years ended December 31, 2108 and 2017:

	Year Ended December 31,			
(in thousands)	2018	2017	Change	% Change
Production taxes	$3,979	$3,321	$658	20 %
Ad valorem taxes	1,504	809	695	86 %
Total production and ad valorem taxes	$5,483	$4,130	$1,353	33 %

The change in production and ad valorem expenses was primarily due to:

- increased production taxes due to higher sales prices;
- increased ad valorem taxes due to properties acquired in Wyoming; and
- discontinuation of the EOR tax credit at one of our Oklahoma units effective July 1, 2017.

The following table summarizes production and ad valorem taxes per Boe data for the years ended December 31, 2018 and 2017:

(per Boe)	Year Ended December 31, 2018	2017	Change	% Change
Production taxes	$3.35	$2.59	$ 0.76	29 %
Ad valorem taxes	1.27	0.63	0.64	102 %
Total production and ad valorem taxes per Boe	$4.62	$3.22	$ 1.40	43 %

The change in production and ad valorem taxes per Boe was primarily due to the changes noted above and decreased production volumes.

Depreciation, depletion and amortization and impairment expenses. The following table provides our non-cash depreciation, depletion and amortization ("DD&A") and impairment expenses for the years ended December 31, 2018 and 2017:

(in thousands)	Year Ended December 31, 2018	2017	Change	% Change
Depreciation, depletion and amortization	$16,751	$17,713	$(962)	(5 %)
Impairment - proved oil and natural gas properties	31,160	24,746	6,414	26 %
Impairment - assets held for sale	—	296	(296)	(100 %)
Total DD&A and impairment expenses	$47,911	$42,755	$5,156	12 %

The change in DD&A was primarily due to:

- decreased depletion rates due to increased reserves;
- reduced asset carrying values due to impairment;
- decreased production volumes; and
- the net impact of the Oklahoma and Wyoming acquisitions and the Southern Oklahoma divestiture.

The change in impairment of proved oil and natural gas properties was primarily due to:

- wellbore issues on a certain Texas project;
- production declines in Texas; and
- certain properties in Texas with no current planned development.

Impairment of proved oil and natural gas properties held for sale for the year ended December 31, 2017, was due to the Nolan County divestiture properties, deemed to meet held-for-sale accounting criteria as of December 31, 2017.

General and administrative expenses. The following table provides components of our G&A for the years ended December 31, 2018 and 2017:

Year Ended
December 31,

(in thousands, except for per Boe)	2018	2017	Change	% Change	
General and administrative expenses	$5,567	$5,285	$ 282	5	%
Non-cash compensation	744	434	310	71	%
Total general and administrative expenses	$6,311	$5,719	$ 592	10	%
General and administrative expenses per Boe	$5.31	$4.46	0.85	19	%

The increase in both G&A and G&A per Boe was primarily due to:

- increased non-cash compensation; and
- increased salaries expense due to bonuses.

Loss on sales of oil and natural gas properties, net. Loss on sales of oil and natural gas properties, net, for the years ended December 31, 2018 and 2017, were $0.5 million and a $4.0 million, respectively. The losses for both periods were primarily due to the Southern Oklahoma divestiture.

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

(in thousands)	Year Ended December 31, 2018	2017	Change	% Change
Interest expense	$6,010	$6,472	$ (462)	(7 %)
Average effective interest rate	5.39 %	3.99 %	1.40 %	35 %

The change in interest expense was primarily due to:

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

Liquidity and Capital Resources

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

Since November 2014, oil prices have been extremely volatile, impacting the way we conduct business. In response, we have implemented a number of adjustments to strengthen our financial position. We have continued to hedge a portion of our production to limit downside and volatility in the prevailing commodity price environment. We have aggressively pursued cost reductions to improve profitability and maximize cash flows. Our primary cost reduction initiatives encompass periodic economic review of each well within our portfolio along with ongoing scrutiny of LOE and G&A. Additionally, in the third quarter 2015, we indefinitely suspended our quarterly cash distributions on common units.

Our liquidity position at February 28, 2019, consisted of approximately $0.1 million of available cash and $36.0 million of available borrowings ($135.0 million borrowing base less $98.0 million outstanding borrowings and $1.0 million outstanding standby letter of credit). We anticipate the net proceeds of the previously announced Strategic Transaction to reduce the outstanding borrowings of our revolving credit facility. Our borrowing base is redetermined in the spring and fall of each year.

Revolving Credit Facility

During the fall 2018 semi-annual borrowing base redetermination of our revolving credit facility completed in December 2018, the lender group increased our borrowing base to $135.0 million effective December 19, 2018. There were no changes to the terms or conditions of the credit agreement. At February 28, 2019, the outstanding borrowings on our revolving credit facility were $98.0 million.

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

Capital Requirements

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

We currently expect capital spending for 2019 for the development, growth and maintenance of our oil and natural gas properties to be approximately $10.9 million. We will adjust our capital program in response to business conditions and operating results along with our evaluation of additional development opportunities that are identified throughout the year.

Commodity Derivative Contracts

Our risk management program is intended to reduce our exposure to commodity price volatility and to assist with stabilizing cash flows. Accordingly, we utilize commodity derivative contracts (commodity price and differential swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. The commodity derivative contracts that we have entered into generally have the effect of providing us with a fixed price or a floor for a portion of our expected future oil production over a fixed period of time. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent or as required by our lenders. At December 31, 2018, we had commodity derivative contracts covering 57% and 48%, respectively, of our estimated 2019 and 2020 average daily production (estimate calculated based on the mid-point of our full year 2019 Boe production guidance as released on March 12, 2019, and multiplied by a 93% oil weighting based on fourth quarter 2018 reported production volumes). See Note 5 to the Consolidated Financial Statements included in Item 8. “Financial Statements and Supplementary Data” for additional information regarding derivatives.

Preferred Units

As of December 31, 2018, we had issued $25.0 million of Class A Preferred Units and $15.0 million of Class B Preferred Units through private placements in August 2016 and January 2018, respectively. Both classes of Preferred Units receive a cumulative, quarterly cash distribution on Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership’s existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Class A or Class B Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end, or as otherwise permitted to accumulate pursuant to the Partnership Agreements. See Note 10 to the Consolidated Financial Statements included in Item 8. “Financial Statements and Supplementary Data” for additional information regarding Preferred Units.

Sources and Uses of Cash

The following table summarizes our net decrease in cash for the years ended December 31, 2018 and 2017:

	Year Ended December 31,			
(in thousands)	2018	2017	Change	% Change
Net cash provided by operating activities	$22,585	$17,246	$5,339	31 %
Net cash (used in) provided by investing activities	(28,816)	6,997	(35,813)	(512 %)
Net cash provided by (used in) financing activities	4,866	(24,770)	29,636	120 %
Net decrease in cash and cash equivalents	$(1,365)	$(527)	$(838)	(159 %)

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

- increased oil sales of $7.5 million due to pricing;
- increased working capital of $4.3 million; offset by
- increased net settlements paid on derivatives of $2.5 million;
- increased LOE of $1.7 million;
- higher production and ad valorem taxes of $1.4 million due to Wyoming acquisitions and increased oil sales pricing; and
- lower debt issuance costs of $0.7 million.

Investing Activities. The change in investing activities was primarily attributable to:

- decreased net proceeds of $21.1 million from the sales of oil and natural gas properties; and
- increased acquisitions of oil and natural gas properties of $16.2 million; offset by
- decreased drilling and completion activities of $1.3 million.

Financing Activities. The change in financing activities was primarily attributable to:

- increased net proceeds on the revolving credit facility of $17.0 million; and
- net proceeds of $14.9 million from the issuance of Class B Preferred Units; offset by
- increased distributions of $1.8 million to Preferred Unitholders; and
- increased payments of $0.5 million for debt issuance cost.

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. See Note 5 to the Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for additional information regarding derivatives.

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, 2018, 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 and natural gas eventually recovered. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see Note 16 to the Consolidated Financial Statements included 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. The liability is accreted each period toward its future value. The discounted capitalized cost is amortized to expense through the depreciation calculation of 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. See Note 7 to the Consolidated Financial Statements included in Item 8. “Financial Statements and Supplementary Data” for additional information.

Valuation of Business Combinations

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 6 to the Consolidated Financial Statements included in Item 8. “Financial Statements and Supplementary Data” for additional information regarding fair value.

Off–Balance Sheet Arrangements

At December 31, 2018, 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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Partners

Mid-Con Energy Partners, LP

Opinion on the financial statements

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, 2018 and 2017, the related consolidated statements of operations, cash flows, and changes in equity for each of the two years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2005.

Tulsa, Oklahoma

March 13, 2019

Mid-Con Energy Partners, LP and subsidiaries

Consolidated Balance Sheets

(in thousands, except number of units)

	December 31,	
	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$467	$1,832
Accounts receivable		
Oil and natural gas sales	3,691	5,262
Other	503	103
Derivative financial instruments	5,666	—
Prepaid expenses and other	118	166
Assets held for sale, net	430	2,058
Total current assets	10,875	9,421
Property and equipment		
Oil and natural gas properties, successful efforts method		
Proved properties	379,441	335,796
Unproved properties	2,928	369
Other property and equipment	427	427
Accumulated depletion, depreciation, amortization and impairment	(175,948)	(129,101)
Total property and equipment, net	206,848	207,491
Derivative financial instruments	2,418	—
Other assets	1,563	2,451
Total assets	$221,704	$219,363
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$141	$593
Related parties	3,732	1,631
Derivative financial instruments	—	4,252
Accrued liabilities	2,024	603
Liabilities related to assets held for sale	—	77
Total current liabilities	5,897	7,156
Derivative financial instruments	—	666
Long-term debt	93,000	99,000
Other long-term liabilities	47	70
Asset retirement obligations	26,001	10,249
Commitments and contingencies		
Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	21,715	20,534
Class B convertible preferred units - 9,803,921 and 0 issued and outstanding, respectively	14,635	—
Equity, per accompanying statements		
General partner	(786)	(572)
Limited partners- 30,436,124 and 30,090,463 units issued and outstanding, respectively	61,195	82,260
Total equity	60,409	81,688
Total liabilities, convertible preferred units and equity	$221,704	$219,363

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, 2018	2017
Revenues		
Oil sales	$65,206	$57,689
Natural gas sales	1,130	1,240
Other operating revenues	778	—
Gain (loss) on derivatives, net	5,674	(1,945)
Total revenues	72,788	56,984
Operating costs and expenses		
Lease operating expenses	22,537	20,805
Production and ad valorem taxes	5,483	4,130
Other operating expenses	945	—
Impairment of proved oil and natural gas properties	31,160	24,746
Impairment of proved oil and natural gas properties held for sale	—	296
Depreciation, depletion and amortization	16,751	17,713
Dry holes and abandonments of unproved properties	612	—
Accretion of discount on asset retirement obligations	721	520
General and administrative	6,311	5,719
Total operating costs and expenses	84,520	73,929
Loss on sales of oil and natural gas properties, net	(509)	(3,950)
Loss from operations	(12,241)	(20,895)
Other (expense) income		
Interest income	3	11
Interest expense	(6,010)	(6,472)
Other (expense) income	(15)	60
Gain (loss) on settlements of asset retirement obligations	10	(37)
Total other expense	(6,012)	(6,438)
Net loss	(18,253)	(27,333)
Less: Distributions to preferred unitholders	4,456	3,063
Less: General partner's interest in net loss	(214)	(324)
Limited partners' interest in net loss	$(22,495)	$(30,072)
Limited partners' interest in net loss per unit		
Basic and diluted	$(0.74)	$(0.99)
Weighted average limited partner units outstanding		
Limited partner units (basic and diluted)	30,328	30,002

See accompanying notes to consolidated financial statements

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Mid-Con Energy Partners, LP and subsidiaries

Consolidated Statements of Cash Flows

(in thousands)

	Year Ended December 31,	
	2018	2017
Cash Flows from Operating Activities		
Net loss	$(18,253)	$(27,333)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	16,751	17,713
Debt issuance costs amortization	678	1,384
Accretion of discount on asset retirement obligations	721	520
Impairment of proved oil and natural gas properties	31,160	24,746
Impairment of proved oil and natural gas properties held for sale	—	296
Dry holes and abandonments of unproved properties	612	—
(Gain) loss on settlements of asset retirement obligations	(10)	37
Cash paid for settlements of asset retirement obligations	(128)	(95)
Mark to market on derivatives		
(Gain) loss on derivatives, net	(5,674)	1,945
Cash settlements paid for matured derivatives	(6,928)	(369)
Cash settlements received from early termination of derivatives	—	582
Cash premiums paid for derivatives, net	(401)	(5,048)
Loss on sales of oil and natural gas properties	509	3,950
Non-cash equity-based compensation	744	434
Changes in operating assets and liabilities		
Accounts receivable	1,571	40
Other receivables	(204)	150
Prepaids and other	(61)	(655)
Accounts payable - trade and accrued liabilities	(210)	427
Accounts payable - related parties	1,708	(1,478)
Net cash provided by operating activities	22,585	17,246
Cash Flows from Investing Activities		
Acquisitions of oil and natural gas properties	(21,243)	(5,034)
Additions to oil and natural gas properties	(8,617)	(9,947)
Additions to other property and equipment	—	(137)
Proceeds from sales of oil and natural gas properties	1,044	22,115
Net cash (used in) provided by investing activities	(28,816)	6,997
Cash Flows from Financing Activities		
Proceeds from line of credit	22,000	6,000
Payments on line of credit	(28,000)	(29,000)
Offering costs	—	(99)
Debt issuance costs	(681)	(171)
Proceeds from sale of Class B convertible preferred units, net of offering costs	14,847	—
Distributions to Class A convertible preferred units	(2,500)	(1,500)
Distributions to Class B convertible preferred units	(800)	—
Net cash provided by (used in) financing activities	4,866	(24,770)

Net decrease in cash and cash equivalents	(1,365)	(527)
Beginning cash and cash equivalents	1,832	2,359
Ending cash and cash equivalents	$467	$1,832

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, 2016	$ (248)	29,912	$111,898	$111,650
Equity-based compensation	—	179	434	434
Distributions to Class A convertible preferred units	—	—	(2,000)	(2,000)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(1,063)	(1,063)
Net loss	(324)	—	(27,009)	(27,333)
Balance, December 31, 2017	(572)	30,091	82,260	81,688
Equity-based compensation	—	345	744	744
Distributions to Class A convertible preferred units	—	—	(2,000)	(2,000)
Distributions to Class B convertible preferred units	—	—	(1,100)	(1,100)
Allocation of value to beneficial conversion feature of Class B convertible preferred units	—	—	686	686
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(1,181)	(1,181)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(175)	(175)
Net loss	(214)	—	(18,039)	(18,253)
Balance, December 31, 2018	$ (786)	30,436	$61,195	$60,409

See accompanying notes to consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries

Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Nature of Operations

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

Note 2. Basis of Presentation and 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, 2018 and 2017, and the results of operations, cash flows and changes in equity for the years then ended December 31, 2018 and 2017. 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 development and production of oil and natural gas properties.

Reclassifications

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

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 asset acquisitions 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, 2018 and 2017, 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 adopted ASC 606 effective January 1, 2018, using the modified retrospective approach. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Under ASC 605, we followed the sales method of accounting for oil and natural gas sales revenues in which revenues were recognized on our share of actual proceeds from oil and natural gas sold to purchasers. Revenue recognition required for our oil and natural gas sales contracts by ASC 606 does not differ from revenue recognition required under ASC 605 to account for such contracts. Therefore, we concluded that there was no change in our revenue recognition under ASC 606 and the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018, did not result in an adjustment to retained earnings. We had no significant natural gas imbalances at December 31, 2018 and 2017. During the years ended December 31, 2018 and 2017, we did 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 extracted NGLs from the natural gas stream sold by us to them, we had no ownership in such NGLs. Therefore, we do not report NGLs in our production or proved reserves.

Revenue from Contracts with Customers. Under our oil and natural gas sales contracts, enforceable rights and obligations arise at the time production occurs on dedicated leases as the Partnership promises to deliver goods in the form of oil or natural gas production on contractually-specified leases to the purchasers. Sales of oil and natural gas are recognized at the point that control of the product is transferred to the customer; title and risk of loss to the product generally transfers at the delivery point specified in the contract. The Partnership commits and dedicates for sale all of the crude oil or natural gas production from contractually agreed-upon leases to the purchaser. Our oil contract pricing provisions are tied to a market index, with certain marketing adjustments, including location and quality differentials as well as certain embedded marketing fees. Our natural gas sales revenues are a percentage of the proceeds received by the purchaser for selling the volume of gas produced by the Partnership on a monthly basis. The purchaser sells the volume of natural gas at index rates per Mcf. Payment is typically received 30 to 60 days after the date production is delivered.

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

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

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

Oil and natural gas properties

Our oil and natural gas development 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 of 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 associated with unproved properties are excluded from depletion until proved reserves are established or impairment determined. When proven reserves are established any unproved property costs associated with the project are transferred to proved properties and included in depletion. Unproved properties are assessed at least annually to ascertain whether impairment has occurred. In addition, impairment assessments are made for interim reporting periods if facts and circumstances exist that suggest impairment may have occurred. The impairment test for unproved properties is not based on the estimated fair value of the unproved properties. The impairment assessment includes consideration of our intent to fully develop our unproved properties, remaining lease terms, geological and geophysical evaluations, our drilling results, potential drilling locations, availability of capital, assignment of proved reserves, expected divestitures, anticipated future capital expenditures and economic considerations, among others.

Costs of significant proved 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 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 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. 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 expense 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 exclude 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. The liability is accreted each period toward its future value. The discounted capitalized cost is amortized to expense through the depreciation calculation over the life of the asset 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. 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 (commodity price and differential swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent or as required by our lenders.

Derivatives are recorded at fair value and are presented on a net basis on the consolidated balance sheets as assets or liabilities. We net the fair value of derivatives by counterparty where the right of offset exists and determine the fair value of our 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. On January 1, 2017, we adopted ASU 2016-09 Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based

Payment Accounting (“ASU 2016-09”); therefore, we recognize forfeitures of equity awards as they occur. 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, any remaining issuance costs associated with that debt are expensed.

Income taxes

The Partnership is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, 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 or Loss

Net income or loss is allocated to our general partner in proportion to its pro rata ownership during the period. The remaining net income or loss is allocated to the limited partner unitholders net of Preferred Unit distributions, including accretion of the Preferred Unit beneficial conversion feature. In the event of net income, diluted net income per partner unit reflects the potential dilution of non-vested restricted stock awards and the conversion of Preferred Units to common units.

Non-cash Investing and Supplemental Cash Flow Information

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

	Year Ended December 31,	
(in thousands)	2018	2017
Non-cash investing information		
Change in oil and natural gas properties - accrued capital expenditures	$348	$(310)
Change in oil and natural gas properties - accrued acquisitions	$1,506	$—
Supplemental cash flow information		
Cash paid for interest	$5,052	$5,041

Recently Issued Accounting Standards

Leases. In February 2016, the FASB issued new guidance in ASC 842, Leases ("ASC 842"), which will supersede the current guidance in ASC 840, Leases ("ASC 840"). The core principle of the new guidance is that a lessee should recognize in the statement of financial position a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term for leases currently classified as operating leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. In January 2018, the FASB issued new guidance in ASC 842 to provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under ASC 840.

In July 2018, the FASB issued new guidance in ASC 842 to provide entities with an additional (and optional) transition method to adopt the new leases standard. Under this new transition method, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with ASC 840. An entity that elects this transition method must provide the required ASC 840 disclosures for all periods that continue to be reported in accordance with ASC 840.

The amendments in these ASCs are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The primary effect on the Partnership's consolidated financial statements will be to record assets and obligations for contracts currently recognized as operating leases with a term greater than 12 months and to evaluate operating leases with a term less than or equal to 12 months for accounting policy election. As of December 31, 2018, we estimate that the adoption and implementation of ASC 842 will not result in a material increase in assets and liabilities on the consolidated balance sheet or to the consolidated statement of operations.

The Partnership has made certain accounting policy decisions including that it plans to adopt the short-term lease recognition exemption and establish a balance sheet recognition capitalization threshold. We will utilize the modified retrospective approach to adopting the new standard that will be applied at the beginning of the period adopted, January 1, 2019. We will utilize the transition package of expedients to leases that commenced before the effective date. The Partnership expects for certain lessee asset classes to elect the practical expedient and not separate lease and non-lease components. For these asset classes, the agreements will be accounted for as a single lease component.

Codification Improvements. In July 2018, the FASB issued ASU 2018-09, “Codification Improvements,” (“ASU 2018-09”) which makes amendments to multiple codification topics to clarify, correct errors in, or make minor improvements to the accounting standards codification. The effective date of the standard is dependent on the facts and circumstances of each amendment. Some amendments do not require transition guidance and will be effective upon the issuance of this standard. Many of the amendments in ASU 2018-09 will be effective in annual periods beginning after December 15, 2018. We will adopt this standard in the first quarter of 2019. We are still evaluating the impact of this standard.

On August 17, 2018, the SEC issued a final rule that amends certain of its disclosure requirement that have become redundant, duplicative, overlapping, outdated or superseded, in light of other disclosure requirements, U.S. GAAP or changes in the information environment. The amendments are intended to facilitate the disclosure of information to investors and simplify compliance without significantly altering the total mix of information provided to investors. The final rule amends numerous SEC rules, items and forms covering a diverse group of topics, including, but not limited to, changes in stockholders' equity. The final rule extends to interim periods the annual disclosure requirement in the SEC Regulation S-X, rule 3-04, of presenting changes in stockholders' equity. The registrants will be required to analyze changes in stockholders' equity in the form of a reconciliation for the current quarter and year-to-date interim periods and comparative periods in the prior year. The final rule became effective for all filings submitted on or after November 5, 2018.

Note 3. Acquisitions, Divestitures and Assets Held for Sale

Acquisitions

We adopted ASU 2017-01, "Business Combinations (Topic 805)" effective January 1, 2018. We now evaluate all acquisitions to determine whether they should be accounted for as business combinations or asset acquisitions. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output.

Acquisitions – Asset Acquisitions

During the year ended December 31, 2018, through multiple transactions, we acquired 122,180 net acres of additional leasehold and additional working interests in 352 producing wells (as of December 31, 2018), in Oklahoma and Wyoming, for aggregate purchase price of $15.4 million, net of post-closing adjustments. These acquisitions were accounted for as asset acquisitions.

Acquisitions – Business Combinations

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

Pine Tree

In January 2018, we acquired multiple oil and gas properties located in Campbell and Converse Counties, Wyoming. The Pine Tree acquisition was accounted for as a business combination. We acquired Pine Tree for cash consideration of $8.4 million, after final post-closing purchase price adjustments.

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

(in thousands)	
Fair value of net assets acquired	
Proved oil and natural gas properties	$8,833
Total assets acquired	8,833
Fair value of net liabilities assumed	
Asset retirement obligation	463

Net assets acquired	$8,370

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

	Year Ended December 31,	
(in thousands)	2018	2017
Oil and natural gas sales	$1,116	$ —
Expenses(1)	$714	$ —

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

Wheatland

In June 2017, we acquired multiple oil and natural gas properties located in Oklahoma and Cleveland Counties, Oklahoma, for

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cash consideration of $4.0 million, after final post-closing purchase price adjustments. The Wheatland acquisition was accounted for as a business combination.

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

(in thousands)	
Fair value of net assets acquired	
Proved oil and natural gas properties	$4,305
Other property and equipment	132
Total assets acquired	4,437
Fair value of net liabilities assumed	
Asset retirement obligation	407
Net assets acquired	$4,030

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

	Year Ended December 31,	
(in thousands)	2018	2017
Oil and natural gas sales	$2,774	$1,373
Expenses(1)	$2,085	$1,009

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

Divestitures

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

Nolan County

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

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

	Year Ended December 31,	
(in thousands)	2018	2017

Oil and natural gas sales	$ —$ 564
Expenses[1]	$ —$ 770

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

Southern Oklahoma

In December 2017, we sold the properties located in Southern Oklahoma for cash proceeds, net of expenses, of $21.5 million, after final post-closing purchase price adjustments, and we recognized a loss on the sale of $0.5 million and $4.2 million for the years ended December 31, 2018, and December 31, 2017, respectively.

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,	
(in thousands)	2018	2017
Oil and natural gas sales	$(4)	$9,252
Expenses[(1)]	$(17)	$7,419

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

Assets Held for Sale

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

As of December 31, 2017, certain oil and natural gas properties in Nolan County, Texas, were deemed to meet held-for-sale criteria. The net asset value of the Nolan County divestiture of $1.6 million was presented in “Assets held for sale, net” and a net liability of $0.1 million was presented in “Liabilities related to assets held for sale” on our consolidated balance sheet.

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 Charles R. Olmstead, Executive Chairman of the Board, and Jeffrey R. Olmstead, President and Chief Executive Officer, and approved by the Board. If an employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding.

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

	Number of Common Units
Approved and authorized awards	3,514,000
Unrestricted units granted	(1,300,538)
Restricted units granted, net of forfeitures	(399,424)
Equity-settled phantom units granted, net of forfeitures	(932,669)
Awards available for future grant	881,369

We recognized $0.7 million and $0.4 million of total equity-based compensation expense for the years ended December 31, 2018 and 2017, respectively. These costs are reported as a component of G&A in our consolidated statements of operations.

Unrestricted Unit Awards

During the year ended December 31, 2018, we granted 87,832 unrestricted units with an average grant date fair value of $1.79 per unit. During the year ended December 31, 2017, we granted 25,400 unrestricted units with an average grant date fair value of $2.65 per unit.

Restricted Unit Awards

All restricted units were vested as of December 31, 2018. A summary of our restricted unit awards for the years ended December 31, 2018 and 2017, is presented below:

	Number of Restricted Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2016	76,922	5.67
Units granted	—	—
Units vested	(69,560)	6.39
Units forfeited	(1,000)	5.42
Outstanding at December 31, 2017	6,362	5.42
Units granted	—	—
Units vested	(6,362)	5.42
Units forfeited	—	—
Outstanding at December 31, 2018	—	$ —

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a period of two or three years. During the year ended December 31, 2018, we granted 450,000 equity-settled phantom units with a two-year vesting period and 44,500 equity-settled phantom units with a three-year vesting period. During the year ended December 31, 2017, we granted 27,000 equity-settled phantom awards with a two-year vesting period and 14,500 equity-settled phantom awards with a three-year vesting period. As of December 31, 2018, there were $0.4 million of unrecognized compensation costs related to equity-settled phantom units. These costs are expected to be recognized over a weighted average period of seventeen months.

A summary of our equity-settled phantom unit awards for the years ended December 31, 2018 and 2017, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2016	287,659	1.64
Units granted	41,500	1.60
Units vested	(153,833)	1.70
Units forfeited	(57,831)	1.96
Outstanding at December 31, 2017	117,495	1.45
Units granted	494,500	1.74
Units vested	(257,829)	1.63
Units forfeited	(3,000)	1.31

Outstanding at December 31, 2018	351,166	$ 1.73

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 (commodity price and differential swaps, calls, puts and collars) to manage a portion of our exposure to commodity prices. We enter into commodity derivative contracts or modify our portfolio of existing commodity derivative contracts when we believe market conditions or other circumstances suggest that it is prudent or as required by our lenders. We account for our commodity derivative contracts at fair value. See Note 6 in this section for a description of our fair value measurements.

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

At December 31, 2018, our commodity derivative contracts were in a net asset position with a fair value of $8.1 million, whereas at December 31, 2017, our commodity derivative contracts were in a net liability position with a fair value of $4.9 million. All of our commodity derivative contracts are with major financial institutions that are also lenders under our revolving credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our commodity derivative contracts under lower commodity prices and we could incur a loss. During the two years ended December 31, 2018 and 2017, all of our counterparties have performed pursuant to their commodity derivative contracts.

The following tables summarize the gross fair value by the appropriate balance sheet classification, even when the derivative financial instruments are subject to netting arrangements and qualify for net presentation in our consolidated balance sheets at December 31, 2018 and 2017:

(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the Consolidated Balance Sheet
December 31, 2018			
Assets			
Derivative financial instruments - current asset	$ 5,705	$ (39)	$ 5,666
Derivative financial instruments - long-term asset	2,418	—	2,418
Total	8,123	(39)	8,084
Liabilities			
Derivative financial instruments - current liability	(39)	39	—
Total	(39)	39	—
Net Asset	$ 8,084	$ —	$ 8,084

(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the Consolidated Balance Sheet
December 31, 2017			
Assets			
Derivative financial instruments - current asset	$ 39	$ (39)	$ —
Total	39	(39)	—
Liabilities			
Derivative financial instruments - current liability	(3,890)	(362)	(4,252)
Derivative deferred premium - current liability	(401)	401	—

Derivative financial instruments - long-term liability	(666)	—	(666)
Total	(4,957)	39	(4,918)
Net Liability	$ (4,918)	$ —	$ (4,918)

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

	Year Ended December 31,	
(in thousands)	2018	2017
Net settlements on matured derivatives[1]	$(6,928)	$(369)
Net settlements on early terminations of derivatives[1]	—	582
Net change in fair value of derivatives	12,602	(2,158)
Total gain (loss) on derivatives, net	$5,674	$(1,945)

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

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

Period Covered	Differential Fixed Price	Weighted Average Fixed Price	Total Bbls Hedged/day	Index
Swaps - 2019	$ —	$ 56.14	1,779	NYMEX-WTI
Swaps - 2019	$ (20.15)	$ —	137	WCS-CRUDE-OIL
Swaps - 2020	$ —	$ 54.81	1,199	NYMEX-WTI

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

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	Index
Swaps - 2018	$ 51.33	$ —	$ —	444	NYMEX-WTI
Puts - 2018	$ —	$ 45.00	$ —	164	NYMEX-WTI
Collars - 2018	$ —	$ 44.38	$ 55.52	1,315	NYMEX-WTI
Swaps - 2019	$ 51.48	$ —	$ —	427	NYMEX-WTI

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, 2018 and 2017.

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation approach or related inputs for the years ended December 31, 2018 and 2017.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We account for commodity derivative contracts and their corresponding deferred premiums at fair value on a recurring basis utilizing certain pricing models. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. The Partnership's deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as the Partnership utilizes a net present value calculation to determine the valuation. See Note 5 in this section for a summary of our derivative financial instruments.

The following sets forth, by level within the hierarchy, the fair value of our assets and liabilities measured at fair value on a recurring basis as of December 31, 2018 and 2017:

(in thousands)	Level 1	Level 2	Level 3	Fair Value
December 31, 2018				
Derivative financial instruments - asset	$ —	$8,123	$—	$8,123
Derivative financial instruments - liability	$ —	$39	$—	$39
December 31, 2017				
Derivative financial instruments - asset	$ —	$39	$—	$39
Derivative financial instruments - liability	$ —	$4,556	$—	$4,556
Derivative deferred premiums - liability	$ —	$—	$401	$401

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

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

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

Asset Retirement Obligations

We estimate the fair value of our 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 at the acquisition date. 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 our acquisitions.

Reserves

We calculate the estimated fair values of reserves and properties using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of reserves, future operating and developmental costs, future commodity prices, a market-based weighted average cost of capital rate and the rate at which future cash flows are discounted to estimate present value. We discount future values by a per annum rate of 10% because we believe this amount approximates our long-term cost of capital and accordingly, is well aligned with our internal business decisions. The underlying commodity prices embedded in our estimated cash flows are the product of a process that begins with Level 1 NYMEX-WTI forward curve pricing, less Level 3 assumptions that include location, pricing adjustments and quality differentials. See Note 16 in this section for additional information regarding our oil and natural gas reserves.

Impairment

The need to test oil and natural gas assets for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. If the carrying value of the long-lived assets exceeds the estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. For the years ended December 31, 2018 and 2017, we recorded non-cash impairment of $31.2 million and $24.7 million, respectively.

When oil and natural gas properties are deemed to meet held-for-sale accounting criteria, non-cash impairment expense is recorded to reduce the carrying amount of those assets to their fair value. For the year ended December 31, 2017, we recorded non-cash impairment of $0.3 million related to certain oil and natural gas properties located in Nolan County, Texas, deemed to meet held-for-sale accounting criteria as of December 31, 2017. See Note 3 in this section for additional information regarding the divestiture.

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 successfully drilling a well and determine our ARO by calculating the present value of estimated cash flow related to the estimated future liability. Determining the removal and future restoration obligation requires management to make estimates and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. We are required to record the fair value of a liability for the ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We review our assumptions and estimates of future ARO on an annual basis, or more frequently, if an event or circumstances occur that would impact our assumptions. To the extent future revisions to these assumptions impact the present value of the abandonment liability, management will make corresponding adjustments to both the ARO and the related oil and natural gas property asset balance. The liability is accreted each period toward its future value. 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, 2018 and 2017, 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,	
(in thousands)	2018	2017
Asset retirement obligations - beginning of period	$10,326	$11,331
Liabilities incurred for new wells and interest	15,497	759
Liabilities settled upon plugging and abandoning wells	(138)	(57)
Liabilities removed upon sale of wells	(399)	(2,152)
Revision of estimates	(6)	(75)
Accretion expense	721	520
Asset retirement obligations - end of period	$26,001	$10,326

Note 8. Debt

At December 31, 2018 and 2017, we had outstanding borrowings under our revolving credit facility of $93.0 million and $99.0 million, respectively. Borrowings under the facility are secured by liens on not less than 90% of the value of our proved reserves.

The borrowing base of our revolving credit facility is collectively determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other variables. The borrowing base is subject to scheduled redeterminations in the spring and fall of each year with an additional redetermination, either at our request or at the request of the lenders, during the period between each scheduled borrowing base redetermination. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract. The next regularly scheduled semi-annual redetermination is expected to occur before or during the second quarter of 2019.

Borrowings under the revolving credit facility bear interest at a floating rate based on, at our election, the greater of the prime rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50% and the one month adjusted London Interbank Offered Rate (“LIBOR”) plus 1.0%, all of which are subject to a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or the applicable LIBOR plus a margin that varies from 2.75% to 3.75% per annum according to the borrowing base usage. For the year ended December 31, 2018, the average effective rate was 5.39%. Any unused portion of the borrowing base will be subject to a commitment fee of 0.50% per annum. Letters of credit are subject to a letter of credit fee that varies from 2.75% to 3.75% according to usage.

We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general partnership purposes and for funding distributions to our unitholders. The revolving credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and payments, including distributions, and requires us to maintain hedges covering projected production. If we fail to perform our obligations under these and other covenants, the revolving credit commitments may be terminated and any outstanding indebtedness under the credit agreement, together with accrued interest, could be declared immediately due and payable.

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

During the quarter ended September 30, 2017, we were not in compliance with our leverage ratio calculation. On November 10, 2017, the Partnership received a waiver from the Administrative Agent and the Lenders of our revolving credit facility waiving the noncompliance through December 15, 2017. On December 22, 2017, Amendment 11 to the credit agreement was finalized. The amendment extended the waiver of the leverage ratio default until January 31, 2018. This amendment decreased our borrowing base to $115.0 million effective December 22, 2017, and required the facility usage not exceed $100.0 million. The amendment also required that the cash proceeds received from the Southern Oklahoma divestiture on December 22, 2017, and the Nolan County divestiture on January 9, 2018, be applied to the borrowings outstanding. See Note 3 in this section for more information regarding these divestitures.

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

During the fall 2018 semi-annual borrowing base redetermination of our revolving credit facility completed in December 2018, the lender group increased our borrowing base to $135.0 million effective December 19, 2018. There were no changes to the terms or conditions of the credit agreement. As of December 31, 2018, we were in compliance with our financial covenants.

Note 9. Commitment and Contingencies

Leases

We lease corporate office space in Tulsa, Oklahoma, Abilene, Texas, and Gillette, Wyoming. For the years ended December 31, 2018 and 2017, total lease expenses were $0.3 million. 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)	
2019	$484
2020	469
2021	471
Total	$1,424

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 on August 1st of each year unless either we or the employee gives written notice of termination by the preceding February. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities and authority as the Board may specify from time to time, in roles consistent with such positions that are assigned to them. The agreements stipulate that if there is a change of control, termination of employment, with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $0.3 million to $0.6 million, including the value of vesting of any outstanding units.

Legal

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any 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.

Note 10. Equity

Common Units

At December 31, 2018 and 2017, the Partnership's equity consisted of 30,436,124 and 30,090,463 common units, respectively, representing a 98.8% limited partnership interest in us.

On May 5, 2015, we entered into an Equity Distribution Agreement to sell, from time to time through or to the Managers (as defined in the agreement), up to $50.0 million in common units representing limited partner interests. In connection with the purchase agreement for the Class A Preferred Units described below, we suspended sales of common units pursuant to the Equity Distribution Agreement effective as of the closing date until August 11, 2021, without the consent of a majority of the holders of the outstanding Preferred Units.

Our Partnership Agreement requires us to distribute all of our available cash on a quarterly basis. Our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures and operational needs, including cash from working capital borrowings. As of December 31, 2018, cash distributions to our common units continued to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions. Management and the Board will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. There is no assurance as to future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors.

Preferred Units

The Partnership has issued two classes of Preferred Units. Per accounting guidance, we were required to allocate a portion of the proceeds from Preferred Units to a beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per-share value of our common units at the issuance date) and the proceeds attributed to the class of Preferred Units. The beneficial conversion feature is accreted using the effective yield method over the period from the closing date to the effective date of the holder's conversion right.

The holders of our Preferred Units are entitled to certain rights that are senior to the rights of holders of common units, such as rights to distributions and rights upon liquidation of the Partnership. We pay holders of Preferred Units a cumulative, quarterly cash distribution on Preferred Units then outstanding at an annual rate of 8.0%, or in the event that the Partnership's existing secured indebtedness prevents the payment of a cash distribution to all holders of the Preferred Units, in kind (additional Class A or Class B Preferred Units), at an annual rate of 10.0%. Such distributions will be paid for each such quarter within 45 days after such quarter end, or as otherwise permitted to accumulate pursuant to the Partnership Agreement.

Prior to August 11, 2021, each holder of Preferred Units has the right, subject to certain conditions, to convert all or a portion of their Preferred Units into common units representing limited partner interests in the Partnership on a one-for-one basis, subject to adjustment for splits, subdivisions, combinations and reclassifications of the common units. Upon conversion of the Preferred Units, the Partnership will pay any distributions (to the extent accrued and unpaid as of the then most recent Preferred Units distribution date) on the converted units in cash.

Class A Preferred Units

On August 11, 2016, we completed a private placement of 11,627,906 Class A Preferred Units for an aggregate offering price of $25.0 million. The Class A Preferred Units were issued at a price of $2.15 per Class A Preferred Unit. Proceeds from this issuance were used to fund an acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $24.6 million in connection with the issuance of these Class A Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class A Preferred Units ($18.6 million) and the beneficial conversion feature ($6.0 million). Accretion of the beneficial conversion feature was $1.2 million and $1.1 million for the years ended December 31, 2018 and 2017, respectively. The registration statement registering resales of common units issued or to be issued upon conversion of the Class A Preferred Units was declared effective by the SEC on June 14, 2017.

At December 31, 2018, the Partnership had accrued $0.5 million for the fourth quarter 2018 distributions that will be paid in cash in February 2019. The following table summarizes cash distributions paid on our Class A Preferred Units during the year ended December 31, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2018	July 1, 2017 - December 31, 2017	$ 0.0860	$ 1,000
May 15, 2018	January 1, 2018 - March 31, 2018	$ 0.0430	$ 500
August 22, 2018	April 1, 2018 - June 30, 2018	$ 0.0430	$ 500
November 14, 2018	July 1, 2018 - September 30, 2018	$ 0.0430	$ 500

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

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2017	October 1, 2016 - December 31, 2016	$ 0.0430	$ 500
May 15, 2017	January 1, 2017 - March 31, 2017	$ 0.0430	$ 500
August 14, 2017	April 1, 2017 - June 30, 2017	$ 0.0430	$ 500

Class B Preferred Units

On January 31, 2018, we completed a private placement of 9,803,921 Class B Preferred Units for an aggregate offering price of $15.0 million. The Class B Preferred Units were issued at a price of $1.53 per Class B Preferred Unit. Proceeds from this issuance were used to fund the acquisition of certain oil and natural gas properties located in Campbell and Converse Counties, Wyoming, and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $14.9 million in connection with the issuance of these Class B Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class B Preferred Units ($14.2 million) and the beneficial conversion feature ($0.7 million). Accretion of the beneficial conversion feature was $0.2 million for the twelve months ended December 31, 2018. The registration statement registering resales of common units issued or to be issued upon conversion of the Class B Preferred Units was declared effective by the SEC on May 25, 2018.

At December 31, 2018, the Partnership had accrued $0.3 million for the fourth quarter 2018 distribution that will be paid in cash in February 2019. The following table summarizes cash distributions paid on our Class B Preferred Units during the twelve months ended December 31, 2018:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
May 15, 2018	February 1, 2018 - March 31, 2018	$ 0.0204	$ 200
August 22, 2018	April 1, 2018 - June 30, 2018	$ 0.0306	$ 300
November 14, 2018	July 1, 2018 - September 30, 2018	$ 0.0306	$ 300

Allocations of Net Income or Loss

Net income or loss is allocated to our general partner in proportion to its pro rata ownership during the period. The remaining net income or loss is allocated to the limited partner unitholders net of Preferred Unit distributions, including accretion of the Preferred Unit beneficial conversion feature. In the event of net income, diluted net income per partner unit reflects the potential dilution of non-vested restricted stock awards and the conversion of Preferred Units.

Note 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 managerial, administrative and operational services. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. These expenses are included in G&A in our consolidated statements of operations.

Operating Agreements

We, along with various third parties with an ownership interest in the same property, are parties to standard oil and natural gas joint operating agreements with our affiliate, Mid-Con Energy Operating. We and those third parties pay Mid-Con Energy Operating overhead associated with operating our properties and for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements. The majority of these expenses were included in LOE 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 affiliates, ME3 Oilfield Service and ME2 Well Services. These amounts are either included in LOE in our consolidated statements of operations or are capitalized as part of oil and natural gas properties in our consolidated balance sheets.

Other Agreements

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

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

	Year Ended December 31,	
(in thousands)	2018	2017
Services agreement	$2,685	$2,443
Operating agreements	8,849	6,509
Oilfield services	3,941	3,377
Other Agreements	310	200
Total	$15,785	$12,529

At December 31, 2018, we had a net payable to our affiliate, Mid-Con Energy Operating, of $3.7 million, comprised of a joint interest billing payable of $3.7 million and a payable for operating services and other miscellaneous items of $1.2 million, offset by an oil and natural gas revenue receivable of $1.2 million. At December 31, 2017, we had a net payable to our affiliate Mid-Con Energy Operating of $1.6 million, comprised of a joint interest billing payable of $1.4 million and a payable for operating services of $0.2 million. These amounts were included in accounts payable-related parties in our 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, 2018, sales of oil and natural gas to three purchasers accounted for 83% of our sales. At December 31, 2018, these purchasers accounted for 89% of our outstanding oil and natural gas accounts receivable. For the year ended December 31, 2017, sales of oil and natural gas to four purchasers accounted for 99% of our sales. At December 31, 2017, these purchasers accounted for 98% of our outstanding oil and natural gas accounts receivable. 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 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 voting members of our general partner, and awards are approved by the Board. 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 the performance of the Partnership along with 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

Equity Awards

On January 21, 2019, the Board authorized the issuance of 50,000 unrestricted common units and 573,000 equity-settled phantom units.

Distributions

A cash distribution of $0.0430 per Class A Preferred Unit, or $0.5 million in aggregate, and a cash distribution of $0.0306 per Class B Preferred Unit, or $0.3 million in aggregate, was paid on February 14, 2019, to holders of record as of the close of business on February 7, 2019.

Strategic Transaction

In February 2019, we entered into definitive agreements to sell substantially all of our Texas assets for $60.0 million, subject to customary purchase price adjustments, and to acquire producing properties in Caddo, Grady and Osage Counties, Oklahoma for $27.5 million, subject to customary purchase price adjustments. These agreements are conditioned to close simultaneously on, or about, March 28, 2019, with an effective date the same as the closing date. Net cash proceeds from this transaction will be used to reduce outstanding borrowings on our revolving credit facility.

Commodity Derivative Contracts

On February 28, 2019, we entered into new oil derivative contracts covering a total 758,300 barrels of future production which extend from January 2020 through December 2021.

Note 16. Supplementary Information

Supplementary Oil and Natural Gas Activities

Costs incurred in oil and natural gas property acquisitions and development activities are presented below for the periods indicated:

(in thousands)	Year Ended December 31, 2018	2017
Property acquisition costs:		
Proved	$20,158	$4,665
Unproved	1,085	369
Exploration	—	—
Development	8,617	9,947
Asset retirement obligations	15,491	684
Total costs incurred	$45,351	$15,665

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, 2018 and 2017, were prepared by our reservoir engineers and audited by CG&A, 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, 2016	18,210	6,124	19,231
Revisions of previous estimates [1]	2,355	168	2,383
Extensions, discoveries and other additions [2]	69	—	69
Purchases of reserves in place [3]	1,607	459	1,684
Sales of reserves in place [4]	(2,522)	(38)	(2,529)
Production	(1,209)	(431)	(1,281)
As of December 31, 2017	18,510	6,282	19,557
Revisions of previous estimates [1]	1,484	(1,045)	1,310
Extensions, discoveries and other additions [5]	72	—	72
Purchases of reserves in place [6]	4,968	1,713	5,253
Sales of reserves in place [7]	(133)	(172)	(162)
Production	(1,112)	(457)	(1,188)
As of December 31, 2018	23,789	6,321	24,842
Proved developed reserves:			
December 31, 2017	13,512	4,586	14,276
December 31, 2018	17,634	6,059	18,643
Proved undeveloped reserves:			
December 31, 2017	4,998	1,696	5,281
December 31, 2018	6,155	262	6,199

[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] Extension of our Hardrock Field in the Texas core area as a result of drilling two successful step out wells in 2017.

[3] Represents the purchase of proved reserves as part of our Wheatland acquisition.

[4] Decrease due to the sale of our Southern Oklahoma properties.

[5] Extension of our Hardrock Field in the Texas core area as a result of drilling one successful step out well in 2018.

[6] Represents the purchase of proved reserves as part of our Oklahoma and Wyoming acquisitions.

[7] Decrease due to the sale of several small properties in the Texas core area.

The increase in quantities of proved reserves from December 31, 2016, to December 31, 2017, was due in part to commodity price increases of 1,309 MBoe which extended the economic lives of certain producing properties, offset in part by downward revisions from certain recent results and development plans. Increased oil production was seen as a response to water injection in our Oklahoma and Texas core areas resulting in upward revisions to our proved reserves of 1,074 MBoe. Positive outcomes from step out drilling locations in the Texas core area resulted in an extension within our Hardrock Field and generated an increase in proved reserves of 69 MBoe. During 2017, the acquisition of the Wheatland properties resulted in a positive revision of 1,684 MBoe, and the divestiture of our Southern Oklahoma properties resulted in a decrease in proved reserves of 2,529 MBoe.

The increase in quantities of proved reserves from December 31, 2017, to December 31, 2018, was due in part to commodity price increases of 1,975 MBoe which extended the economic lives of certain producing properties, offset in part by net downward revisions of 1,169 MBoe from certain recent results and development modifications. Increased oil production was seen as a response to water injection in our Oklahoma and Texas core areas, resulting in upward revisions to our proved reserves of 504 MBoe. Positive outcomes from step out drilling locations in the Texas core area resulted in an extension within our Hardrock Field and generated an increase in proved reserves of 72 MBoe. During 2018, the acquisition of the Oklahoma and Wyoming waterflood properties resulted in a positive revision of 5,253 MBoe, and the divestiture of several small properties in the Texas core area resulted in a decrease in proved reserves of 162 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, 2018 and 2017, 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 the Partnership, because we are a non-taxable entity; and
- 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,	
(in thousands)	2018	2017
Future cash inflows	$1,494,349	$927,473
Future production costs	(694,862)	(444,673)
Future development costs, including abandonment costs	(92,973)	(50,868)
Future net cash flow	706,514	431,932
10% discount for estimated timing of cash flow	(358,261)	(224,719)
Standardized measure of discounted cash flow	$348,253	$207,213

The prices utilized in calculating our total proved reserves were $65.56 and $51.34 per Bbl of oil and $3.10 and $2.98 per MMBtu of natural gas for December 31, 2018 and 2017, 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 $62.17 and $49.34 per Bbl of oil and $2.43 and $2.27 per Mcf of natural gas for December 31, 2018 and 2017, respectively. Adjusted natural gas price includes the sale of associated NGLs. During the years ended December 31, 2018 and 2017, we did 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 extracted NGLs from the natural gas stream sold by us to them, we had 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,	
(in thousands)	2018	2017
Standardized measure of discounted future net cash flow, beginning of year	$207,213	$157,285
Changes in the year resulting from:		

Sales, less production costs	(38,316)	(33,994)
Revisions of previous quantity estimates	24,035	28,132
Extensions, discoveries and improved recovery	2,398	3,168
Net change in prices and production costs	102,480	61,504
Net change in income taxes	—	—
Changes in estimated future development costs	4,534	5,173
Previously estimated development costs incurred during the year	8,428	9,726
Purchases of reserves in place	50,242	13,826
Sales of reserves in place	(2,714)	(10,420)
Accretion of discount	20,721	15,729
Timing differences and other	(30,768)	(42,916)
Standardized measure of discounted future net cash flow, end of year	$348,253	$207,213

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, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our 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, 2018.

/s/ Jeffrey R. Olmstead	/s/ Philip R. Houchin
Jeffrey R. Olmstead	Philip R. Houchin
Chief Executive Officer	Chief Financial Officer
March 13, 2019	

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 the Board therefore refer to the officers and the Board 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 has seven members. The NASDAQ listing rules do not require a listed limited partnership, like us, to have a majority of independent directors on the Board 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 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 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 February 28, 2019, the average tenure of the individuals listed below was approximately five years since the Initial Public Offering in December 2011.

Name	Age	Position with Mid-Con Energy GP, LLC
Charles R. "Randy" Olmstead	70	Executive Chairman of the Board
Jeffrey R. Olmstead	42	President, Chief Executive Officer and Director
Philip R. Houchin	41	Chief Financial Officer
Charles L. McLawhorn III	42	Vice President, General Counsel and Corporate Secretary
Sherry L. Morgan	51	Chief Accounting Officer
C. Fred Ball Jr. (1)	74	Director
John W. Brown (1)	72	Director
Wilkie S. Colyer Jr.	34	Director
Peter A. Leidel	62	Director
Cameron O. Smith (1)	68	Director

(1) Member of the Audit Committee and the Conflicts Committee.

The members of our Board are appointed for one-year terms by 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 serve at the discretion of the Board. All of our 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 executive officers and directors.

Charles R. “Randy” Olmstead serves as Executive Chairman of the Board. Mr. Olmstead previously served as Chief Executive Officer and Chairman of the Board 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 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 the Partnership in December 2011. He has been President, Chief Financial Officer and Chairman of the Board 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 extensive management and operational experience in the oil and natural gas industry, along with his leadership skills to our Board.

Jeffrey R. Olmstead, President, Chief Executive Officer, and Director, 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 Mid-Con Energy I, LLC, and Mid-Con Energy II, LLC, from 2007 until both entities were merged into the Partnership 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's experience in the oil and natural gas industry and his finance background provides a critical resource to our Board.

Philip R. Houchin, Chief Financial Officer, became an officer in March 2018. Prior to joining us, Mr. Houchin was Executive Vice President and Chief Lending Officer of Patriot Bank. As a part of a management team and group of investors, Mr. Houchin assisted with the purchase of the bank in 2009 and eventual sale in 2017. Prior to Patriot Bank, Mr. Houchin held various positions with Summit Bank and Bank of Oklahoma as part of his 18 years in the commercial banking industry in Tulsa, Oklahoma. Mr. Houchin graduated from the University of Oklahoma with a Bachelor of Business Administration in Finance and from the Southwest Graduate School of Banking at the Cox Business School at Southern Methodist University.

Charles L. McLawhorn III, Vice President, General Counsel and Corporate Secretary of our general partner, became an officer 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, a privately held oil and gas company. 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 a Juris Doctor degree from the University of Oklahoma College of Law.

Sherry L. Morgan, Chief Accounting Officer, became an officer in July 2015, and previously served as our Assistant Controller from July 2008 until July 2015. Additionally, Ms. Morgan served as acting Principal Financial Officer from December 2017 to March 2018. 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.

C. Fred Ball Jr., Director, is the Chairman of the Audit Committee. Mr. Ball 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 Boards of BOK Financial Corporation, the National Teachers Associates Life Insurance Company, where he is also a member of the Audit Committee, and Southern Methodist University, where he resides on the Executive Board of the Edwin L. Cox School of Business. Mr. Ball earned his Bachelor of Science in Engineering and Master of Business Administration from Southern Methodist University. Mr. Ball brings extensive insights and the knowledge of finance and banking to our Board.

John W. Brown, Director, has served as Chairman of Par Investments LLC, a private investment firm focused on energy related investments, since June 2005. Since July 1991, Mr. Brown has served as the General Partner of Premier Capital, Ltd., a private energy focused investment banking firm that has been an advisor of energy transactions in excess of $400 million since 2003. Mr. Brown served on the Board of Directors of Halcon Resources from March

2016 through September 2016. From 2001 to 2003, Mr. Brown served as a Director of Friedman, Billings, Ramsey Group, a publicly traded full service banking firm focused on energy investment banking transactions. Prior to that, Mr. Brown served as an Associate at EnCap Investments, L.C., from 2000 to 2001; was the Founder and General Partner of WesAl Capital, Ltd., a private energy investment banking firm with the late William E. Simon, former Secretary of the Treasury, and Alvin Shoemaker, former Chairman of First Boston from 1986 to 1991; and was the Founder, and President of Westwood Resources Company, a privately held independent oil and gas company, from 1981 to 1984. Mr. Brown practiced law from 1973 until 1981. He earned a Bachelor of Arts Degree from Southern Methodist University and a Juris Doctor Degree and Masters of Laws Degree from Southern Methodist University Law School. Mr. Brown brings extensive experience and knowledge of finance and energy to our Board.

Wilkie S. Colyer Jr., Director, currently serves as President, CEO and Director of Contango Oil & Gas Company (“Contango”), a publicly traded oil and natural gas producer. Prior to joining Contango, Mr. Colyer was employed by Goff Capital, the family office of John Goff, from 2007 until August 2018. Most recently, he served as Principal for Goff Capital, Inc. and Senior Vice President, Investments of Goff Focused Strategies LLC, an exempt reporting advisor with the SEC and the State of Texas. Mr. Colyer was responsible for the firms’ energy investing and has held a material role in public and private investments in sectors including financial services and real estate, among others. Mr. Colyer currently serves on the Board of Directors of two oil and natural gas producers, Resolute Energy Corporation and Contango. 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.

Peter A. Leidel, Director, 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 Boards of Mid-Con Energy III, LLC, and Mid-Con Energy Operating since June 2011. Mr. Leidel was a member of the Boards of both 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 the Partnership 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 extensive private experience within and perspective on the energy sector to our Board.

Cameron O. Smith, Director, is also Chairman of the Conflicts Committee. From 2011 to 2018, Mr. Smith served as an advisor to the energy group at Warburg Pincus, LLC, a private equity firm. 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 extensive knowledge of the oil and natural gas industry, along with expertise in investment banking, to our Board.

Committees of the Board of Directors

The Board, has an Audit Committee and a Conflicts Committee, but does not have a Compensation Committee. The NASDAQ listing rules do not require a listed limited partnership to establish a Compensation Committee or a Nominating and Corporate Governance Committee. Equity grants to directors and employees are administered by the voting members of the general partner and approved by the Board.

Audit Committee

The Audit Committee consists of Messrs. Ball, Brown and Smith, with Mr. Ball serving as committee Chairman. The Audit Committee held four quarterly meetings in 2018. Our Board has affirmatively determined that each member of the Audit Committee meets the independence and experience standards established by the NASDAQ listing rules and the rules of the SEC. Our Board has also reviewed the financial expertise of Mr. Ball and affirmatively determined that he is an "Audit Committee Financial Expert," as determined by the rules of the SEC. Our Board 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. Our independent registered public accounting firm is given unrestricted access to the Audit Committee and our management, as necessary.

During the last fiscal year, and earlier this year in preparation for the filing with the SEC of the Partnership’s Form 10-K for the year ended December 31, 2018, the Audit Committee:

- reviewed and discussed the Partnership’s audited consolidated financial statements as of and for the year ended December 31, 2018, with management, the independent consultants and the independent registered public accountants;
- considered the adequacy of the Partnership’s internal controls and the quality of its financial reporting, and discussed these matters with management, the independent consultants and the independent registered public accountants;
- reviewed and discussed with the independent registered public accountants (i) their judgments as to the quality of the Partnership’s accounting policies, (ii) the written disclosures and letter from the independent registered public accountants required by Public Company Accounting Oversight Board Independence Rules, and the independent registered public accounts’ independence, and (iii) the matters required to be discussed by the Public Company Accounting Oversight Board’s Auditing Standard No. 1301, Communications with Audit Committees;
- discussed with management, the independent consultants and the independent registered public accounts the process by which the Partnership’s Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer make the

certifications required by the SEC in connection with filing of the Partnership's periodic reports with the SEC, including reports on Forms 10-K and 10-Q;

- pre-approved all auditing services and non-audit services to be performed for the Partnership by the independent registered public accounts as required by all the applicable rules promulgated pursuant to the Exchange Act, considered whether the rendering of non-audit services was compatible with maintaining Grant Thornton LLP's independence, and concluded that Grant Thornton LLP's independence was not compromised by the provision of such services (details regarding the fees paid to Grant Thornton LLP in fiscal year 2018 for audit services, tax services and all other services, are set forth in "Principal Accounting Fees and Services" below); and
- based on the reviews and discussions referred to above, recommended to the Board that the audited consolidated financial statements referred to above to be included in the Partnership's Form 10-K for the year ended December 31, 2018.

Conflicts Committee

The Conflicts Committee currently consists of Messrs. Ball, Brown and Smith, who meet the independence standards established by the NASDAQ 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 out its duties. The Conflicts Committee did not hold any meetings in 2018.

Board Leadership Structure and Role in Risk Oversight

Leadership of our Board is vested in the Chairman of the Board. Although our Chief Executive Officer currently does not serve as Chairman of the Board, we currently have no policy prohibiting our current, or any future Chief Executive Officer, from serving as Chairman of the Board. The Board, 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 Board has also determined that having the Chief Executive Officer serve as a director will enhance understanding and communication between management and the Board, allow for better comprehension and evaluation of our operations and ultimately improve the ability of the Board 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 has delegated to management the primary responsibility for enterprise-level risk management, including cybersecurity risks, while retaining responsibility for oversight of our executive officers in that regard. Our executive officers offer an enterprise-level risk assessment to the Board at least once every year.

Non-Management Executive Sessions and Unitholder Communications

NASDAQ 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 Board meeting, 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 four quarterly meetings and three special meetings in 2018. 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 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 concerning their beneficial ownership of such securities. Based solely on a review of the copies of reports on Form 3, Form 4 and Form 5 and amendments thereto furnished to us and written representations from the executive officers and directors, we believe that all filing requirements applicable to the officers and directors and greater than 10% unitholders were complied with for the fiscal year ended December 31, 2018, except for one late filing for each executive officer pertaining to the grant of unvested units during 2018.

Code of Ethics

The governance of Mid-Con Energy GP 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 has adopted a Code of Business Conduct that applies to all officers, directors and its employees and affiliates. A copy of the Code of Business Conduct is available on our website at www.midconenergypartners.com. We will provide a copy of the 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 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 believes that it is management's role to speak for the Partnership. Our Board also believes that any communications between members of the Board 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 of our Board members, including non-management directors and non-management directors as a group, by writing to the director or directors in care of the corporate secretary 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 listing rules do not require a listed limited partnership to establish a compensation committee, and we do not have a compensation committee. The Board performs the functions of a compensation committee, and although the Board does not currently appoint a compensation committee, it may do so in the future. The Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth below.

Our “named executive officers” for the year ended December 31, 2018, were:

Jeffery R. Olmstead
Charles R. “Randy” Olmstead
Charles L. McLawhorn III

The foregoing report shall not be deemed to be incorporated by reference by any general statement or reference to this 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 the Partnership's 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;
- short-term incentive payments in the form of discretionary cash bonuses;
- short-term incentive payments in the form of long-term equity-based compensation; and
- benefits.

The voting 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 voting members of our general partner and approved by the Board.

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, and Jeffrey R. Olmstead, President and Chief Executive Officer.

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 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 is intended to promote the interests of the Partnership and encourage superior performance by providing equity awards to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating and ME3 Oilfield Service. 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 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.

The Long-Term Incentive Program is currently administered by the voting members of our general partner, and approved by the Board. 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 voting members of the general partner take into consideration the performance of the Partnership along with discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package.

Equity Compensation Plan Information as of February 28, 2019:

Plan category	Number of securities remaining available for future issuance under equity compensation plans	
Equity compensation plans approved by security holders	268,369	(1)
Equity compensation plans not approved by security holders	—	
Total	268,369	

(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. We do not provide perquisites to the named executive officers.

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, 2018 and 2017. 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
Jeffrey R. Olmstead	2018	$257,633	$29,000	$105,000	$ 4,869	(1)	$396,502
President, CEO and Director	2017	$249,900	$—	$—	$ 7,497	(1)	$257,397
Charles R. Olmstead	2018	$198,000	$25,000	$105,000	$ 4,537	(1)	$332,537
Executive Chairman of the Board	2017	$207,000	$—	$—	$ 6,210	(1)	$213,210
Charles L. McLawhorn III	2018	$150,942	$17,400	$78,750	$ 4,701	(1)	$251,793
VP, General Counsel and Secretary	2017	$139,824	$—	$—	$ 4,195	(1)	$144,019

(1) Includes Registrant's contributions to a defined contribution plan.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2018:

Name	Number of Units That Have Not Yet Vested		Market Value of Units That Have Not Yet Vested (1)
Jeffrey R. Olmstead	40,000	(2)	$ 33,200
Charles R. Olmstead	40,000	(2)	$ 33,200
Charles L. McLawhorn III	30,000	(2)	$ 24,900

(1) Based on the closing price of our common units at December 31, 2018.
(2) These restricted units vest equally over three years beginning March 1, 2018.

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

The below table summarizes the material terms of the employee agreements that provide for payments to named executives in connection with the resignation, retirement or other termination of a named executive officer or a change in control:

	Term Without Cause or Good Reason	Death or Disability	Change in Control
Accrued amounts [1]	Amounts earned during employment	Amounts earned during employment	Amounts earned during employment
Base Salary	one year	one year	two years
Bonus [2]	Lesser of: “target annual bonus”, or average of previous two annual bonuses	“target annual bonus”	Twice the lesser of: “target annual bonus”, or average of previous two annual bonuses
Health-care coverage [3]	Amount of Cobra	Amount of Cobra	Amount of Cobra
Equity awards	Accelerated vesting	Accelerated vesting	Accelerated vesting

(1) Includes salary, vacation, benefits and unreimbursed business expenses.

(2) “Target annual bonus” as defined in the employment agreement.

(3) Lump sum for officer and dependents, if applicable.

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.

The following tables reflect estimates of our allocated portion of the amount of incremental compensation due to each named executive officer 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, 2018, 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	$ 198,000	$ 198,000	$ 396,000
Restricted Stock/Units	33,200	33,200	33,200
Performance Shares/Units	41,500	41,500	41,500
Health & Welfare	36,630	36,630	36,630
Total	$ 309,330	$ 309,330	$ 507,330

Jeffrey R. Olmstead	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following Change in Control
Cash Severance	$ 259,608	$ 259,608	$ 519,216

Restricted Stock/Units	33,200	33,200	33,200
Performance Shares/Units	41,500	41,500	41,500
Health & Welfare	54,846	54,846	54,846
Total	$ 389,154	$ 389,154	$ 648,762

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 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 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 2018, directors who were not officers or employees received an annual retainer of $30,000, 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.

The following table discloses the cash, unit awards and other compensation earned, paid or awarded to each of our non-management directors during the year ended December 31, 2018:

Name [1]	Fee Earned or Paid in Cash	Unit Awards [2]	Total
Peter Adamson III	$ 43,000	$ 17,500 [3]	$60,500
C. Fred Ball Jr.	$ 38,000	$ 17,500 [3]	$55,500
John W. Brown	$ 37,000	$ 22,750 [4]	$59,750
Wilkie S. Colyer Jr.	$ 34,000	$ 17,500 [3]	$51,500
Peter A. Leidel	$ 34,000	$ 17,500 [3]	$51,500
Cameron O. Smith	$ 43,000	$ 17,500 [3]	$60,500

(1) Messrs. Olmstead and Olmstead are 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 February 2018. There were no awards outstanding at fiscal year-end.

(3) Reflects 10,000 unit awards granted in February 2018.

(4) Reflects 13,000 unit awards granted in February 2018.

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

As of February 15, 2019, the following table sets forth the beneficial ownership of our voting securities that are owned by:

- beneficial owners of more than 5% of our common units;
- each of the directors and Named Executive Officers 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 Beneficially Owned [1]	Percentage of Common Units Beneficially Owned		Class A Preferred Units Beneficially Owned [2]	Percentage of Class A Preferred Units Beneficially Owned		Class B Preferred Units Beneficially Owned [2]	Percentage of Class B Preferred Units Beneficially Owned	
Mid-Con Energy III, LLC[3]	3,714,659	12.1	%	930,223	8.0	%	522,875	5.3	%
John C. Goff[4]	678,000	2.2	%	4,790,697	41.2	%	9,281,046	94.7	%
Robert W. Stallings[5]	—	—	%	1,860,465	16.0	%	—	—%	
James R. Reis[5][6]	—	—	%	1,627,907	14.0	%	—	—%	
Robert J. Raymond[7]	2,985,652	9.7	%	232,558	2.0	%	—	—%	
Charles R. Olmstead[8]	814,178	2.7	%	—	—%		—	—%	
Jeffrey R. Olmstead[8]	532,429	1.7	%	—	—%		—	—%	
Charles L. McLawhorn III[8]	41,990	*		—	—%		—	—%	
Sherry L. Morgan[8]	55,318	*		—	—%		—	—%	
Philip R. Houchin[8]	105,000	*		—	—%		—	—%	
C. Fred Ball Jr.[8]	111,310	*		—	—%		—	—%	
Peter A. Leidel[8]	285,305	*		—	—%		—	—%	
Cameron O. Smith[8]	67,340	*		—	—%		—	—%	
Wilkie S. Colyer Jr.[8]	24,000	*		—	—%		—	—%	
John W. Brown[8]	40,000	*		—	—%		—	—%	
All named executive officers, directors and director nominees as a group (10 people)	2,076,870	6.8	%	—	—%		—	—%	

* Represents less than 1.0% of the outstanding class of voting securities.

(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. As of February 15, 2019, 30,658,958 common units were outstanding.

(2) In August 2016, we issued 11,627,906 Class A Preferred Units. In January 2018, we issued 9,803,921 Class B 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 prior to August 11, 2021, in whole or in part, subject to certain conversion thresholds.

(3) C/o Mid-Con Energy GP, LLC, 2431 E. 61st Street, Suite 850, Tulsa, Oklahoma 74136. If Mid-Con Energy III, LLC converted all of their Preferred Units into common units, Mid-Con Energy III, LLC would be deemed to

beneficially own, directly or indirectly, 5,167,757 common units or 14.4% of the common units outstanding.

(4) This disclosure is based on an amendment to the Schedule 13D filed with the SEC on January 3, 2019, 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) GFS REN GP, LLC ("GFS REN"); (vii) GFS Management, LLC ("GFS Management"); (viii) GFS; (ix) GFS Energy GP, LLC ("GFS Energy"); (x) GFT Strategies, LLC ("GFT"); (xi) John C. Goff 2010 Family Trust ("Goff Family Trust"); (xii) Goff Ren Holdings, LLC ("Goff Ren II"); (xiii) Goff MCEP II, LP ("Goff MCEP II"); (xiv) Goff Focused Energy Strategies, LP ("Goff Energy"); (xv) Goff Family Investments, LP ("Family Investments"); and (xvi) GFS MCEP GP, LLC ("GFS MCEP"). As of the date of such filing, John C. Goff may be deemed the beneficial owner of (1) 1,860,465 Class A Preferred Units and 784,314 Class B Preferred Units owned by Goff REN, (2) 2,697,674 Class A Preferred Units owned by Goff MCEP Holdings, (3) 232,558 Class A Preferred Units owned by Goff Foundation, (4) 784,314 Class B Preferred Units owned by Goff Ren II, (5) 5,098,039 Class B Preferred Units owned by Goff MCEP II, (6) 2,614,379 Class B Preferred Units owned by Goff Energy and (7) 160,000 common units owned by Family Investments. As the manager of Goff MCEP Holdings and the general partner of Family Investments, Goff Capital may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the Class A Preferred Units owned by Goff MCEP Holdings and the common units owned by Family Investments. As the manager of Goff Ren and Goff Ren II, GFS Ren may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the Class A and Class B Preferred Units owned by Goff Ren and the Class B Preferred Units owned by Goff Ren II. As the general partner of Goff MCEP II, GFS MCEP may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the Class B Preferred Units owned by Goff MCEP II. As the general partner of Goff Energy, GFS Energy may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the Class B Preferred Units owned by Goff Energy. As the managing manager of GFS Ren, GFS MCEP and GFS Energy, GFS Management may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the (1) Class A and Class B Preferred Units owned by Goff Ren, (2) Class B Preferred Units owned by Goff Ren II, (3) Class B Preferred Units owned by Goff MCEP II and (4) Class B Preferred Units owned by Goff Energy. As the managing manager of GFS Management, GFS may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the (1) Class A and Class B Preferred Units owned by Goff Ren, (2) Class B Preferred Units owned by Goff Ren II, (3) Class B Preferred Units owned by Goff MCEP II and (4) Class B Preferred Units owned by Goff Energy. As the controlling equity holder of GFS, GFT may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the (1) Class A and Class B Preferred Units owned by Goff Ren, (2) Class B Preferred Units owned by Goff Ren II, (3) Class B Preferred Units owned by Goff MCEP II and (4) Class B Preferred Units owned by Goff Energy. As the managing member of GFT and controlling shareholder of Goff Capital, Goff Family Trust may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the (1) Class A Preferred Units owned by Goff MCEP Holdings, (2) Class A and Class B Preferred Units owned by Goff Ren, (3) Class B Preferred Units owned by Goff Ren II, (4) Class B Preferred Units owned by Goff MCEP II, (5) Class B Preferred Units owned by Goff Energy, (6) common units owned by Family Investments and (7) common units owned by Goff Family Trust. As trustee of Goff Family Trust, controlling shareholder of Goff Capital, sole board member of Goff Foundation, and Chief Executive Officer and managing member of GFS, John C. Goff may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the (1) Class A Preferred

Units owned by Goff MCEP Holdings, (2) Class A and Class B Preferred Units owned by Goff Ren, (3) Class B Preferred Units owned by Goff Ren II, (4) Class B Preferred Units owned by Goff MCEP II, (5) Class B Preferred Units owned by Goff Energy, (6) Class A Preferred Units owned by Goff Foundation, (7) common units owned by Family Investments and (8) common units owned by Goff Family Trust. If Mr. Goff converted all of his Preferred Units into common units, Mr. Goff would be deemed to beneficially own, directly or indirectly, 14,749,743 common units or 32.5% of the common units outstanding. Mr. Goff and his applicable affiliates disclaim beneficial ownership of all of the common units and Preferred Units, including the common units into which the Preferred Units are convertible, except to the extent of its pecuniary interest. Mr. Goff has a principal business address of 500 Commerce Street, Suite 700, Fort Worth, Texas 76102.

(5) 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 Class A Preferred Units owned by GAINSCO (which are also reported as Class A Preferred Units beneficially owned by Mr. Reis in the table above), and (2) 465,116 Class A 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 and the sole power to dispose or direct the disposition of the Class A Preferred Units of SCG Ventures and the common units into which such Class A Preferred Units are convertible and the shared power to vote or direct the vote and the shared power to dispose or direct the disposition of such securities of GAINSCO. If Mr. Stallings converted all of his Preferred Units into common units, Mr. Stallings would be deemed to beneficially own, directly or indirectly, 1,860,465 common units or 5.7% of the common units outstanding. Mr. Stallings disclaims beneficial ownership of all of the Class A Preferred Units and the common units into which the Class A 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 Class A Preferred Units of SCG Ventures and the common units into which the Class A 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.

(6) 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 Class A Preferred Units) and the common units into which such Class A 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 Class A Preferred Units, which are also reported as Class A Preferred Units beneficially owned by Mr. Stallings in the table above). If Mr. Reis converted all of his Preferred Units into common units, Mr. Reis would be deemed to beneficially own, directly or indirectly, 1,627,907 common units or 5.0% of the common units outstanding. Mr. Reis disclaims beneficial ownership of all of the Class A Preferred Units and the common units into which the Class A 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.

(7) This disclosure is based on the Schedule 13G filed with the SEC on February 8, 2019. As the sole member of RR Advisors, LLC, RCH Black Fund GP, LP, and RCH Black Fund, LP, Mr. Robert J. Raymond may be deemed to have the sole power to vote or direct the vote and the sole power to dispose or direct the disposition of the Preferred Units of RR Advisors, LLC, (232,558 Class A Preferred Units) and the common units into which such Class A Preferred Units are convertible and the shared power to vote or direct the vote and the shared power to dispose or direct the disposition of such securities of RR Advisors, LLC, RCH Black Fund GP, LP, and RCH Black Fund LP. If Mr. Raymond converted all of his Preferred Units into common units, Mr. Raymond would be deemed to beneficially own, directly or indirectly, 3,218,210 common units or 9.5% of the common units outstanding. Mr. Raymond disclaims beneficial ownership of all of the Class A Preferred Units and the common units into which the Class A

Preferred Units are convertible, except to the extent of his pecuniary interest therein. Mr. Raymond has a principal business address of 3953 Maple Avenue, Suite 180, Dallas, Texas 75219.

(8) 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, 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, 2018, our general partner has an approximate 1.2% interest in us. Any distributions made 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 Related Parties

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, 2018, we paid Mid-Con Energy Operating $2.7 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, 2018, we paid Mid-Con Energy Operating $8.8 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 affiliates, ME3 Oilfield Service and ME2 Well Services. 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, 2018, we paid Mid-Con Energy Operating $3.9 million for oilfield services performed by ME3 Oilfield Service and ME2 Well Services.

Other Agreements

We are party to monitoring fee agreements with Bonanza and GFS pursuant to which we pay Bonanza and GFS a quarterly monitoring fee in connection with monitoring the purchasers' investments in the Preferred Units. For the year ended December 31, 2018, total monitoring fee expenses were $0.3 million. These expenses were included in G&A in our consolidated statements of operations.

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 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 (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 (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 (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 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 does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the Board. For a discussion of the independence of the Board, 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, 2018 and 2017. 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 Form 10–K for the year ended December 31, 2018, were approved by the audit committee.

Fees paid to Grant Thornton, LLP are as follows:

	2018	2017
Audit fees	$398,500	$393,000
Audit-related fees	—	—
Tax fees	113,705	131,152
Total	$512,205	$524,152

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	First Amendment to First Amended and Restated Agreement of Limited Partnership of Mid-Con Energy Partners, LP, dated as of August 11, 2016 (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 August 16, 2016).
3.5	Second Amendment to First Amended and Restated Agreement of Limited Partnership of Mid-Con Energy Partners, LP, dated as of January 31, 2018 (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 31, 2018).
3.6	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 November 17, 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 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on November 18, 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 Amendment No.11 to Credit Agreement, dated as of December 22, 2017, 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 10.2 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 29, 2017).

10.14 Amendment No.12 to Credit Agreement, dated as of January 31, 2018, 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 January 31, 2018).

10.15 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).

10.16* 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)).

10.17*	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).
10.18*	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).
10.19*	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).
10.20	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).
10.21	Class B Convertible Preferred Unit Purchase Agreement, dated January 23, 2018, 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 January 29, 2018).

10.22*	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).
10.23*	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).
10.24	Purchase and Sale Agreement, dated as of November 8, 2017, among Mid-Con Energy Properties, LLC, as seller, and Exponent Energy III LLC, as purchaser thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's quarterly report on Form 10-Q filed with the SEC on November 14, 2017).
10.25	Amendment to Purchase and Sale Agreement, dated December 22, 2017, among Mid-Con Energy Properties, LLC, as seller, and Exponent Energy III LLC, as purchaser 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 29, 2017).
10.26	Purchase and Sale Agreement, dated as of February 15, 2019, among Mid-Con Energy Properties, LLC, as purchaser, and Scout Energy Group IV, LP, Scout Energy Partners IV-A, LP, Scout Energy Group I, LP, and Scout Energy Partners I-A, LP, as seller thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's quarterly report on Form 8-K filed with the SEC on February 19, 2019).
10.27	Purchase and Sale Agreement, dated as of February 15, 2019, among Mid-Con Energy Properties, LLC, as seller, and Scout Energy Group IV, LP, as purchaser thereto (incorporated by reference to Exhibit 10.2 to Mid-Con Energy Partners, LP's quarterly report on Form 8-K filed with the SEC on February 19, 2019).
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 Principal Financial Officer
32.1+	Section 1350 Certification of Chief Executive Officer
32.2+	Section 1350 Certification of Principal 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
*Represents management compensatory plans and agreements.

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:	March 13, 2019	By:	/s/ Philip R. Houchin Philip R. Houchin 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 March 13, 2019.

Signature	Title	Date
/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead	Chief Executive Officer and Director (Principal Executive Officer)	March 13, 2019
/s/ Philip R. Houchin Philip R. Houchin	Chief Financial Officer (Principal Financial Officer)	March 13, 2019
/s/ Sherry L. Morgan Sherry L. Morgan	Chief Accounting Officer	March 13, 2019
/s/ Charles R. Olmstead Charles R. Olmstead	Executive Chairman of the Board	March 13, 2019
/s/ C. Fred Ball Jr. C. Fred Ball Jr.	Director	March 13, 2019
/s/ John W. Brown John W. Brown	Director	March 13, 2019
/s/ Wilkie S. Colyer Jr. Wilkie S. Colyer Jr.	Director	March 13, 2019
/s/ Peter A. Leidel Peter A. Leidel	Director	March 13, 2019
/s/ Cameron O. Smith Cameron O. Smith	Director	March 13, 2019

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