UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8–K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15 (d)
OF THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported): November 20, 2020

MID-CON ENERGY PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**001-35374**	**45-2842469**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

2431 E. 61st Street, Suite 800
Tulsa, Oklahoma
(Address of principal executive offices)

74136
(Zip code)

(918) 748-3361
(Registrant's telephone number, including area code)
N/A
(Former name or former address, if changed since last report)

☐ Written communication pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading symbol	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	**MCEP**	**NASDAQ Global Select Market**

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).
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. ☐

Item 8.01 **Other Events**

As previously announced, on October 25, 2020, Mid-Con Energy Partners, LP, a Delaware limited partnership ("Mid-Con" or the "Company"), entered into an Agreement and Plan of Merger (the "Merger Agreement"), with Contango Oil & Gas Company, a Texas corporation ("Contango"), Michael Merger Sub LLC, a Delaware limited liability company and a wholly-owned, direct subsidiary of Contango ("Merger Sub"), and Mid-Con Energy GP, LLC, a Delaware limited liability company and the general partner of Mid-Con. Upon the terms and subject to the conditions of the Merger Agreement, Mid-Con will merge with and into Merger Sub (the "Merger"), with Merger Sub surviving the Merger as a limited liability company and a wholly owned, direct subsidiary of the Contango.

As contemplated by the Merger Agreement, on November 20, 2020, Contango filed a registration statement on Form S-4 (the "Registration Statement"), which includes a joint consent statement/information statement/prospectus of Mid-Con and Contango. The Registration Statement contains certain historical financial information of Mid-Con which has been recast to reflect the 1-for-20 reverse unit split (the "Reverse Split") that occurred on April 9, 2020 (the "Recast Financial Information"). Accordingly, the Company is filing this Current Report on Form 8-K to update certain financial information and related disclosures included in the Company's Annual Report on Form 10-K for the year ended December 31, 2019 (the "2019 Form 10-K"), originally filed on March 12, 2020, to reflect the recast financial information presented in the Registration Statement. The information in this Current Report on Form 8-K is not an amendment to, or restatement of, the 2019 Form 10-K.

The following items of the 2019 Form 10-K are being revised as reflected in Exhibit 99.1 to this Current Report on Form 8K:

- Part I, Item 1A. Risk Factors;
- Part II, Item 8. Financial Statements and Supplementary Data;
- Part III, Item 11. Executive Compensation; and
- Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Except for minor, non-substantive revisions, only the following notes within Part II, Item 8, Financial Statements and Supplementary Data have been revised from their previous presentation:

- Note 4, Equity Awards;
- Note 10, Equity; and
- Note 18, Reverse Unit Split.

The changes referred to above had no impact on the Company's historical consolidated financial position, results of operations or cash flows, as reflected in the recast Consolidated Financial Statements contained in Exhibit 99.1 to this Current Report on Form 8K.

This report, including Exhibit 99.1, generally does not reflect events occurring after the filing of the 2019 Form 10-K and generally does not modify or update the disclosures in the 2019 Form 10-K, other than as required to reflect Reverse Split. Without limitation of the foregoing, this report does not purport to update the MD&A contained in the 2019 Form 10-K for any forward-looking statements. More current information is contained in our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2020, June 30, 2020 and September 30, 2020 and our Current Reports on Form 8-K filed with the Securities Exchange Commission with respect to events occurring after December 31, 2019. This report should be read in conjunction with the 2019 Form 10-K, our Forms 10-Q for the quarterly periods ended March 31, 2020, June 30, 2020 and September 30, 2020 and our Current Reports on Form 8-K filed subsequent to the 2019 Form 10-K.

Item 9.01 **Financial Statements and Exhibits**

(d) *List of Exhibits*

23.1	Consent of Grant Thornton LLP
99.1	Revised Part I—Item 1A. "Risk Factors", Revised Part II—Item 8. "Financial Statements and Supplementary Data" and Item 8. "Financial Statements and Supplementary Data" and Revised Part III—Item 11 "Executive Compensation" and Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" of Mid-Con Energy Partners, LP's Annual Report on Form 10-K for the year ended December 31, 2019.

SIGNATURES

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

MID-CON ENERGY PARTNERS, LP

By: Mid-Con Energy GP, LLC
its general partner

Dated:	November 20, 2020	By:	*/s/Sherry L. Morgan*
			Sherry L. Morgan
			Chief Executive Officer

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 12, 2020 (except for Note 18 as to which the date is November 20, 2020), with respect to the consolidated financial statements of Mid-Con Energy Partners, LP for the year ended December 31, 2019 included in this current report on Form 8-K dated November 20, 2020. We consent to the incorporation by reference of said report in the Registration Statements of Mid-Con Energy Partners, LP on Forms S-3 (File No. 333-224590, File No. 333-214536, File No. 333-195669 and File No. 333-187012) and on Forms S-8 (File No. 333-208203 and File No. 333-179161).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
November 20, 2020

MID-CON ENERGY PARTNERS, LP

UPDATES TO FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2019

EXPLANATORY NOTE

Mid-Con Energy Partners, LP, a Delaware limited partnership ("Mid-Con," the "Company," "we," "us" or "our"), is filing this Exhibit 99.1 to reissue certain financial information and related disclosures included in its report on Form 10-K for the year ended December 31, 2019 (the "2019 Form 10-K"), originally filed with the Securities and Exchange Commission (the "SEC") on March 12, 2020, to recast certain historical financial information of Mid-Con to reflect the 1-for-20 reverse unit split (the "Reverse Split") that occurred on April 9, 2020 (the "Recast Financial Information").

As previously announced, on October 25, 2020, Mid-Con entered into an Agreement and Plan of Merger (the "Merger Agreement"), with Contango Oil & Gas Company, a Texas corporation ("Contango"), Michael Merger Sub LLC, a Delaware limited liability company and a wholly-owned, direct subsidiary of Contango ("Merger Sub"), and Mid-Con Energy GP, LLC, a Delaware limited liability company and the general partner of Mid-Con ("Mid-Con GP"). Upon the terms and subject to the conditions of the Merger Agreement, Mid-Con will merge with and into Merger Sub (the "Merger"), with Merger Sub surviving the Merger as a limited liability company and a wholly-owned, direct subsidiary of the Contango.

This Exhibit 99.1 updates the information in the following Items of the 2019 Form 10-K as initially filed in order to recast certain historical information as discussed above: Part I, Item 1A (Risk Factors); Part II, Item 8 (Financial Statements and Supplementary Data); Part III, Item 11(Executive Compensation); and Part III, Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters). The information contained in this Exhibit 99.1 does not reflect any changes, activities, or events occurring subsequent to the filing of the 2019 Form 10-K on March 12, 2020, and generally does not modify or update the disclosures in the 2019 Form 10-K, other than as required to reflect the Reverse Split. Therefore, this Exhibit 99.1 should be read in conjunction with the reports and other information that the company has filed with the SEC on or after March 12, 2020, including the company's Quarterly Reports on Form 10-Q for the periods ended March 31, 2020, June 30, 2020 and September 30, 2020 and our Current Reports on Form 8-K filed subsequent to the 2019 Form 10-K.

FORWARD-LOOKING STATEMENT

In accordance with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, this Exhibit 99.1 contains certain forward-looking statements which reflect the company's view with respect to future events and future financial performance, based on information available to us on the date of filing our 2019 Form 10-K, as filed on March 12, 2020, updated only to the extent necessary to reflect the Reverse Split described in the Explanatory Note to this Exhibit 99.1. Forward-looking statements are all statements other than statements of historical fact.

All such forward-looking statements are subject to risks and uncertainties, and the company's future results of operations could differ materially from its historical results or current expectations reflected by such forward-looking statements. Some of these risks are discussed in the 2019 Form 10-K, including in Item 1A. "Risk Factors" and include, without limitation, uncertainties related to our pending Merger, as defined herein, with Contango Oil & Gas Co., including, but not limited to, disruption of management time from ongoing business operations due to the Merger, the risk of any litigation relating to the Merger and the risk that the parties may not be able to satisfy the conditions to the completion of the Merger in a timely manner or at all; our ability to continue as a going concern; volatility of commodity prices; supply and demand of oil and natural gas; 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; our 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; world-wide epidemics, including COVID-19, and the related effects of sheltering in place; competition in the oil and natural gas industry; environmental liabilities; counterparty credit risk; governmental regulation and taxation; compliance with NASDAQ Global Select Market listing requirements; developments in oil and natural gas *producing countries, including increases and decreases in supply from Russia and OPEC; and plans, objectives, expectations and intentions..*

Forward-looking statements, which can generally be identified by the use of such terminology as "may," "can," "potential," "expect," "project," "target," "anticipate," "estimate," "forecast," "believe," "think," "could," "continue," "intend," "seek," "plan," and similar expressions contained in this Exhibit 99.1 and the Transition Report, are not guarantees of future performance or events. Any forward-looking statements are based on the company's assessment of current industry, financial and economic information, which by its nature is dynamic and subject to rapid and possibly abrupt changes, which the company may or may not be able to control. Further, the company may make changes to its business plans that could or will affect its results. While management believes that these forward-looking statements are reasonable when made, there can be no assurance that future developments that affect us will be those that we anticipate and have identified. The forward-looking statements should be considered in the context of the risk factors listed above and discussed in greater detail elsewhere in this Exhibit 99.1, the 2019 Form 10-K, our Quarterly Report on Form 10-Q for the quarter ended September 30, 2020 and in our Current Reports on Form 8-K filed with the Securities and Exchange Commission. Investors and prospective investors are cautioned not to rely unduly on such forward-looking statements, which speak only as of the date hereof. Management disclaims any obligation to update or revise any forward-looking statements contained herein to reflect new information, future events or developments.

In certain places in this Exhibit 99.1 and the 2019 Form 10-K, the company may refer to reports published by third parties that purport to describe trends or developments in energy production and drilling and exploration activity. The company does so for the convenience of its investors and potential investors and in an effort to provide information available in the market that will lead to a better understanding of the market environment in which the company operates. The company specifically disclaims any responsibility for the accuracy and completeness of such information and undertakes no obligation to update such information.

PART I

This section highlights information that is discussed in more detail in the remainder of the document. We use the terms "we," "our," "us," the "Partnership" or the "Company" to refer to Mid-Con Energy Partners, LP.

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 it does, 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, 2019, front-month NYMEX-WTI oil futures prices ranged from a high of $76.41 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, acts of terrorism or sabotage, and world-wide epidemics, including the coronavirus;
- 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 $0.4 million in non-cash impairment expense for the year ended December 31, 2019. 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 and 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 2019 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 $241.2 million to $153.1 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, 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 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 approximately 76% of our sales for the year ended December 31, 2019. 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, 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, with amendments proposed in 2018 and 2019. 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. As of March 3, 2020, 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 also provides 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, 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. The Board, including the independent directors, is chosen entirely by 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 March 3, 2020, 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 and officers of our general partner with their own choices and thereby influence the decisions made by the Board 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, 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 March 3, 2020, the voting members of our general partner, our Mid-Con Affiliate and Yorktown own 267,945 common units and 18,000 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, which could have a material adverse effect on us and our unitholders.

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

As previously disclosed, the Partnership received a deficiency letter on March 26, 2019, from the Listing Qualifications Department (the "Staff") of NASDAQ, notifying the Partnership that, for 30 consecutive business days, the bid price for the Partnership's common units had closed below the minimum $1.00 per unit requirement for continued inclusion on the NASDAQ Global Select Market. In accordance with NASDAQ rules, the Partnership was provided an initial period of 180 calendar days, or until September 23, 2019, to regain compliance with the Bid Price Rule.

On September 24, 2019, the Staff notified the Partnership in writing that while the Partnership had not regained compliance with the Bid Price Rule, it was being granted an additional 180-day compliance period, or until March 23, 2020, to regain compliance with the Bid Price Rule. The Staff's determination was based on the Partnership having met the continued listing requirement for market value of publicly held shares and all other applicable requirements for initial listing on NASDAQ, with the exception of the Bid Price Rule.

On March 3, 2020, the Partnership announced that the Board has approved a 1-for-10 reverse unit split on the Partnership's common units, to become effective after the market closes on March 23, 2020. This reverse split is intended for the Partnership to regain compliance with the Bid Price Rule. There can be no assurance that we will be able to regain compliance with the Bid Price Rule. If we do regain compliance with the Bid Price Rule, there can be no assurance that we will be able to maintain compliance with its continued listing requirements, or that our common units will not be delisted from NASDAQ in the future. In addition, we may be unable to meet other applicable listing requirements of NASDAQ, in which case our common units could be delisted notwithstanding our ability to demonstrate compliance with the Bid Price Rule.

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. Delisting also could have other negative results, including the loss of institutional investors or the loss of business development opportunities.

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 still 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 remains 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" during the taxable year, 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. Business interest expense that we are not entitled to fully deduct will be allocated to each unitholder as excess business interest and 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. Any excess business interest expense allocated to a unitholder will reduce the unitholder's tax basis in its partnership interest in the year of the allocation even if the expense does not give rise to a deduction to the unitholder in that year.

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.

Distributions to non-U.S. unitholders will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. unitholders will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. 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 final implementing regulations. Proposed regulations addressing these issues have been released, which, if and when finalized, will end this suspension of the withholding rules. It is unclear, however, when such regulations will be finalized. Tax-exempt entities and non-U.S. persons should consult a tax advisor before investing in our units.

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

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Although 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.

PART III

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, 2019 and 2018, the related consolidated statements of operations, cash flows, and changes in equity for each of the two years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

Change in accounting principle
As discussed in Note 15 to the consolidated financial statements, the Partnership has changed its method of accounting for leases in the year ended December 31, 2019 due to the adoption of FASB Accounting Standards Codification Topic 842, Leases.

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 12, 2020 (except for Note 18, as to which the date is November 20, 2020)

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

	December 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 255	$ 467
Accounts receivable	6,853	4,194
Derivative financial instruments	—	5,666
Prepaid expenses	87	118
Assets held for sale	365	430
Total current assets	7,560	10,875
Property and equipment		
Oil and natural gas properties, successful efforts method		
Proved properties	261,375	379,441
Unproved properties	3,125	2,928
Other property and equipment	1,262	427
Accumulated depletion, depreciation, amortization and impairment	(72,303)	(175,948)
Total property and equipment, net	193,459	206,848
Derivative financial instruments	730	2,418
Other assets	1,020	1,563
Total assets	$ 202,769	$ 221,704
LIABILITIES, CONVERTIBLE PREFERRED UNITS AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 320	$ 141
Related parties	6,902	3,732
Derivative financial instruments	1,944	—
Accrued liabilities	795	2,024
Other current liabilities	430	—
Total current liabilities	10,391	5,897
Long-term debt	68,000	93,000
Other long-term liabilities	457	47
Asset retirement obligations	30,265	26,001
Commitments and contingencies		
Class A convertible preferred units - 11,627,906 issued and outstanding, respectively	22,964	21,715
Class B convertible preferred units - 9,803,921 issued and outstanding, respectively	14,829	14,635
Equity, per accompanying statements		
General partner	(793)	(786)
1,521,806	56,656	61,195
Total equity	55,863	60,409
Total liabilities, convertible preferred units and equity	$ 202,769	$ 221,704

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, 2019	Year Ended December 31, 2018
Revenues		
Oil sales	$ 63,163	$ 65,206
Natural gas sales	1,304	1,130
Other operating revenues	1,280	778
(Loss) gain on derivatives, net	(10,246)	5,674
Total revenues	55,501	72,788
Operating costs and expenses		
Lease operating expenses	31,870	22,537
Production and ad valorem taxes	5,486	5,483
Other operating expenses	2,068	945
Impairment of proved oil and natural gas properties	384	31,160
Impairment of assets held for sale	65	—
Depreciation, depletion and amortization	10,621	16,751
Dry holes and abandonments of unproved properties	—	612
Accretion of discount on asset retirement obligations	1,596	721
General and administrative	8,572	6,311
Total operating costs and expenses	60,662	84,520
Gain (loss) on sales of oil and natural gas properties, net	9,671	(509)
Income (loss) from operations	4,510	(12,241)
Other (expense) income		
Interest income	10	3
Interest expense	(5,166)	(6,010)
Other expense	(3)	(15)
Gain on sale of other assets	123	—
(Loss) gain on settlements of asset retirement obligations	(73)	10
Total other expense	(5,109)	(6,012)
Net loss	(599)	(18,253)
Less: Distributions to preferred unitholders	4,643	4,456
Less: General partner's interest in net loss	(7)	(214)
Limited partners' interest in net loss	$ (5,235)	$ (22,495)
Limited partners' interest in net loss per unit		
Basic and diluted	$ (3.40)	$ (14.83)
Weighted average limited partner units outstanding		
Limited partner units (basic and diluted)	1,538	1,516

See accompanying notes to consolidated financial statements

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

	Year Ended December 31, 2019	Year Ended December 31, 2018
Cash flows from operating activities		
Net loss	$ (599)	$ (18,253)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	10,621	16,751
Debt issuance costs amortization	702	678
Accretion of discount on asset retirement obligations	1,596	721
Impairment of proved oil and natural gas properties	384	31,160
Impairment of assets held for sale	65	—
Dry holes and abandonments of unproved properties	—	612
Loss (gain) on settlements of asset retirement obligations	73	(10)
Cash paid for settlements of asset retirement obligations	(97)	(128)
Mark to market on derivatives		
Loss (gain) on derivatives, net	10,246	(5,674)
Cash settlements paid for matured derivatives, net	(949)	(6,928)
Cash premiums paid for derivatives	—	(401)
(Gain) loss on sales of oil and natural gas properties	(9,671)	509
Gain on sale of other assets	(123)	—
Non-cash equity-based compensation	696	744
Changes in operating assets and liabilities		
Accounts receivable	(2,856)	1,367
Prepaid expenses and other assets	70	(61)
Accounts payable - trade and accrued liabilities	97	(210)
Accounts payable - related parties	1,554	1,708
Net cash provided by operating activities	11,809	22,585
Cash flows from investing activities		
Acquisitions of oil and natural gas properties	(3,331)	(21,243)
Additions to oil and natural gas properties	(13,868)	(8,617)
Proceeds from sales of oil and natural gas properties	33,453	1,044
Proceeds from sale of other assets	123	—
Net cash provided by (used in) investing activities	16,377	(28,816)
Cash flows from financing activities		
Proceeds from line of credit	11,000	22,000
Payments on line of credit	(36,000)	(28,000)
Debt issuance costs	(198)	(681)
Proceeds from sale of Class B convertible preferred units, net of offering costs	—	14,847
Distributions to Class A convertible preferred units	(2,000)	(2,500)
Distributions to Class B convertible preferred units	(1,200)	(800)
Net cash (used in) provided by financing activities	(28,398)	4,866
Net decrease in cash and cash equivalents	(212)	(1,365)
Beginning cash and cash equivalents	467	1,832
Ending cash and cash equivalents	$ 255	$ 467

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, 2017	$ (572)	1,505	$ 82,260	$ 81,688
Equity-based compensation	—	17	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)	1,522	61,195	60,409
Equity-based compensation	—	19	696	696
Distributions to Class A convertible preferred units	—	—	(2,000)	(2,000)
Distributions to Class B convertible preferred units	—	—	(1,200)	(1,200)
Accretion of beneficial conversion feature of Class A convertible preferred units	—	—	(1,249)	(1,249)
Accretion of beneficial conversion feature of Class B convertible preferred units	—	—	(194)	(194)
Net loss	(7)	—	(592)	(599)
Balance, December 31, 2019	$ (793)	1,541	$ 56,656	$ 55,863

See accompanying notes to consolidated financial statements

Note 1. Organization and Nature of Operations

Nature of Operations

Mid-Con Energy Partners, LP is a publicly held Delaware limited partnership formed in July 2011 that engages in the ownership, acquisition 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, 2019 and 2018, and the results of operations, cash flows and changes in equity for the years then ended December 31, 2019 and 2018. The accompanying consolidated financial statements have been prepared in accordance with 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.

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, 2019 and 2018, 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, 2019 and 2018.

Revenue from Contracts with Customers. Under our oil and natural gas sales contracts, enforceable rights and obligations arise at the time production occurs on dedicated leases as the Partnership promises to deliver goods in the form of oil or natural gas production on contractually-specified leases to the purchasers. Sales of oil and natural gas are recognized at the point that control of the product is transferred to the customer; title and risk of loss to the product generally transfers at the delivery point specified in the contract. We do not extract NGLs from our natural gas production prior to the sale and transfer of title of the natural gas stream to our purchasers. While some of our purchasers extracted NGLs from the natural gas stream sold by us to them, we had no ownership in such NGLs. The Partnership commits and dedicates for sale all of the oil or natural gas production from contractually agreed-upon leases to the purchaser. Our oil contract pricing provisions are tied to a market index, with certain marketing adjustments, including location and quality differentials as well as certain embedded marketing fees. The majority of our natural gas contract pricing provisions are tied to a market index less customary deductions, such as gathering, processing and transportation. Payment is typically received 30 to 60 days after the date production is delivered.

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

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

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

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 in this section 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 in this section for additional discussion 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 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 in this section 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. We recognize forfeitures of equity awards as they occur.

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)	**2019**	**2018**
Non-cash investing information		
Change in oil and natural gas properties - assets received in exchange	$ 38,533	$ —
Change in oil and natural gas properties - accrued capital expenditures	$ 1,663	$ 348
Change in oil and natural gas properties - accrued acquisitions	$ (1,462)	$ 1,506
Supplemental cash flow information		
Cash paid for interest	$ 4,644	$ 5,052

Recently Issued Accounting Standards

In June 2016, the FASB issued ASC 326, *Financial Instruments- Credit Losses* ("ASC 326"), which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. For smaller reporting companies, this guidance is effective for fiscal years beginning after December 15, 2022, and early adoption is permitted. We plan to adopt this standard on January 1, 2023, and are currently evaluating the impact of adoption on our consolidated financial statements.

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.

Assets and liabilities assumed in acquisitions accounted for as business combinations are recorded in our consolidated balance sheets at their estimated fair values as of the acquisition date using assumptions that represent Level 3 fair value measurement inputs. See Note 6 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 statements of operations. The operations and cash flows of divested properties are eliminated from our ongoing operations.

Pine Tree Business Combination

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

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

(in thousands)		
Fair value of net assets acquired		
Proved oil and natural gas properties	$	8,833
Total assets acquired		8,833
Fair value of net liabilities assumed		
Asset retirement obligation		463
Net assets acquired	$	8,370

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

	Year Ended December 31,			
(in thousands)		**2019**		**2018**
Oil and natural gas sales	$	1,349	$	1,116
Expenses(1)	$	1,211	$	714

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

Strategic Transaction

In March 2019, we simultaneously closed the previously announced definitive agreements to sell substantially all of our oil and natural gas properties located in Texas for $60.0 million and to purchase certain oil and natural gas properties located in Osage, Grady and Caddo Counties in Oklahoma for an aggregate purchase price of $27.5 million, both agreements subject to customary purchase price adjustments. We received net proceeds of $32.5 million at the close of this Strategic Transaction ("Strategic Transaction") of which $32.0 million was used to reduce borrowings outstanding on our revolving credit facility. The acquired properties were accounted for as an asset acquisition. A gain on the sale of oil and natural gas properties of $9.3 million was reported in the consolidated statements of operations.

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)		**2019**		**2018**
Oil and natural gas sales	$	4,688	$	25,861
Expenses(1)	$	3,358	$	39,214

(1) Expenses include LOE, production and ad valorem taxes, accretion, depletion, impairment and dry hole costs.

Nolan County Divestiture

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

Assets Held for Sale

Land in Southern Oklahoma met held-for-sale criteria as of December 31, 2019 and 2018. The carrying value of $0.4 million was presented in "Assets held for sale" on our consolidated balance sheet. Impairment of $0.1 million was recorded to reduce the carrying value of the land to its estimated fair value at December 31, 2019.

Note 4. Equity Awards

We have a long-term incentive program (the "Long-Term Incentive Program") for employees, officers, consultants and directors of our general partner and its affiliates, including Mid-Con Energy Operating and ME3 Oilfield Service, who perform services for us. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, unrestricted units, restricted units, phantom units, distribution equivalent rights granted with phantom units and other types of awards. The Long-Term Incentive Program is administered by the voting members of the general partner 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, 2019:

	Number of Common Units
Approved and authorized awards	175,700
Unrestricted units granted	(67,527)
Restricted units granted, net of forfeitures	(19,971)
Equity-settled phantom units granted, net of forfeitures	(74,533)
Awards available for future grant	13,669

We recognized $0.7 million of total equity-based compensation expense for the years ended December 31, 2019 and 2018. 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, 2019, we granted 2,500 unrestricted units with an average grant date fair value of $20.80 per unit. During the year ended December 31, 2018, we granted 4,392 unrestricted units with an average grant date fair value of $35.73per unit.

Equity-Settled Phantom Unit Awards

Equity-settled phantom units vest over a period of two or three years. During the year ended December 31, 2019, we granted 25,500 equity-settled phantom units with a two-year vesting period and 3,300 equity-settled phantom units with a three-year vesting period. During the year ended December 31, 2018, we granted 22,500 equity-settled phantom awards with a two-year vesting period and 2,225 equity-settled phantom awards with a three-year vesting period. As of December 31, 2019, there were $0.3 million of unrecognized compensation costs related to equity-settled phantom units. These costs are expected to be recognized over a weighted average period of thirteen months.

A summary of our equity-settled phantom unit awards for the years ended December 31, 2019 and 2018, is presented below:

	Number of Equity-Settled Phantom Units	Average Grant Date Fair Value per Unit
Outstanding at December 31, 2017	5,875	$ 29.00
Units granted	24,725	34.80
Units vested	(12,891)	32.60
Units forfeited	(150)	26.20
Outstanding at December 31, 2018	17,559	34.55
Units granted	28,800	20.80
Units vested	(16,908)	27.60
Units forfeited	(900)	30.20
Outstanding at December 31, 2019	28,551	$ 25.00

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, 2019, our commodity derivative contracts were in a net liability position with a fair value of $1.2 million, whereas at December 31, 2018, our commodity derivative contracts were in a net asset position with a fair value of $8.1 million. All of our commodity derivative contracts are with major financial institutions that are also lenders under our revolving credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our commodity derivative contracts under lower commodity prices and we could incur a loss. During the years ended December 31, 2019 and 2018, 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, 2019 and 2018:

(in thousands)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts Presented in the Consolidated Balance Sheet
December 31, 2019			
Assets			
Derivative financial instruments - long-term asset	$ 1,635	$ (905)	$ 730
Total	1,635	(905)	730
Liabilities			
Derivative financial instruments - current liability	(1,944)	—	(1,944)
Derivative financial instruments - long-term liability	(905)	905	—
Total	(2,849)	905	(1,944)
Net Liability	$ (1,214)	$ —	$ (1,214)

(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

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

(in thousands)	Year Ended December 31, 2019	Year Ended December 31, 2018
Net settlements on matured derivatives(1)	$ (949)	$ (6,928)
Net change in fair value of derivatives	(9,297)	12,602
Total (loss) gain on derivatives, net	$ (10,246)	$ 5,674

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

At December 31, 2019 and 2018, our commodity derivative contracts had maturities at various dates through December 2021 and were comprised of commodity price and differential swaps and collar contracts. At December 31, 2019, 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 - 2020	$ 55.81	$ —	$ —	1,931	NYMEX-WTI
Swaps - 2021	$ 55.78	$ —	$ —	672	NYMEX-WTI
Collars - 2021	$ —	$ 52.00	$ 58.80	672	NYMEX-WTI

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

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

Note 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, 2019 and 2018.

Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation approach or related inputs for the years ended December 31, 2019 and 2018.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We account for commodity derivative contracts and their corresponding deferred premiums at fair value on a recurring basis utilizing certain pricing models. Inputs to the pricing models include publicly available prices from a compilation of data gathered from third parties and brokers. We validate the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Any deferred premiums associated with our commodity derivative contracts are categorized as Level 3, as we utilize 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, 2019 and 2018:

(in thousands)	Level 1	Level 2	Level 3	Fair Value
December 31, 2019				
Derivative financial instruments - asset	$ —	$ 1,635	$ —	$ 1,635
Derivative financial instruments - liability	$ —	$ 2,849	$ —	$ 2,849
December 31, 2018				
Derivative financial instruments - asset	$ —	$ 8,123	$ —	$ 8,123
Derivative financial instruments - liability	$ —	$ 39	$ —	$ 39

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

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

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

Asset Retirement Obligations

We estimate the fair value of our 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 begin with Level 1 NYMEX-WTI forward curve pricing, less Level 3 assumptions that include location, pricing adjustments and quality differentials. See Note 17 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 expense is recognized for the difference between the estimated fair value and the carrying value of the assets. For the years ended December 31, 2019 and 2018, we recorded impairment expense of $0.4 million and $31.2 million, respectively. Additionally, for the year ended December 31, 2019, we recorded impairment expense related to assets held for sale of $0.1 million to reduce the carrying amount of the assets to their fair value.

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 and is recorded in our consolidated statement of operations. The discounted capitalized cost is amortized to expense through the depreciation calculation over the life of the assets based on proved developed reserves. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability.

For the years ended December 31, 2019 and 2018, 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)	**2019**	**2018**
Asset retirement obligations - beginning of period	$ 26,001	$ 10,326
Liabilities incurred for new wells and interests	8,840	15,497
Liabilities settled upon plugging and abandoning wells	(24)	(138)
Liabilities removed upon sale of wells	(5,795)	(399)
Revision of estimates	(353)	(6)
Accretion expense	1,596	721
Asset retirement obligations - end of period	$ 30,265	$ 26,001

Note 8. Debt

At December 31, 2019 and 2018, we had outstanding borrowings under our revolving credit facility of $68.0 million and $93.0 million, respectively. Our current revolving credit facility matures in May 2021. 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 during the spring of 2020.

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, 2019, the average effective rate was 5.56%. 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, and restrictions on certain transactions and payments, including distributions, and requires us to maintain hedges covering projected production. If we fail to perform our obligations under these and other covenants, the revolving credit commitments may be terminated and any outstanding indebtedness under the credit agreement, together with accrued interest, could be declared immediately due and payable. As of December 31, 2019, we were in compliance with our financial covenants.

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

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

On March 28, 2019, in conjunction with closing the Strategic Transaction and serving as our spring redetermination, Amendment 13 to the credit agreement was executed, decreasing our borrowing base to $110.0 million. The amendment also required that the leverage ratio be calculated on a building, period-annualized basis, beginning the second quarter of 2019. See Note 3 in this section for further discussion of the Strategic Transaction.

On December 6, 2019, Amendment 14 to the credit agreement was executed, decreasing the borrowing base of the Partnership's revolving credit facility to $95.0 million. The amendment also extended the maturity date of the revolving credit facility to May 1, 2021, and provided for a benchmark rate replacement to address the transition of LIBOR in 2021. Under the terms of the amendment, the Partnership is required to have a Consolidated Funded Indebtedness to Consolidated EBITDAX of less than 3.0 to 1.0 to make any borrowings above the borrowing cap of $85.0 million, and must maintain a maximum Leverage Ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX that does not exceed:

- 4.0 to 1.0 for the quarter ending December 31, 2019,
- 3.75 to 1.0 for the quarter ending March 31, 2020, and
- 3.5 to 1.0 for the quarter ending June 30, 2020, and thereafter.

Note 9. Commitment and Contingencies

Services Agreement

We are party to a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides certain services to us including management, administrative and operational services. 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 and Jeffrey R. Olmstead. 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 $0.7 million, including the value of vesting of any outstanding units.

Change in Control Severance Plan

On July 24, 2019, the Board adopted a Change in Control Severance Plan that provides severance benefits to certain key management and employees of the general partner and its affiliates. The Change in Control Severance Plan provides for the payment of cash compensation and certain other benefits to eligible employees in the event of a change in control and a qualifying termination of employment. The obligations under the Change in Control Severance Plan are generally based on the terminated employee's cash compensation and position within the Partnership. Depending on the facts and circumstances associated with a potential change in control, the total payments made pursuant to the Change in Control Severance Plan could be material. No liability has been recorded at December 31, 2019, associated with the Change in Control Severance Plan. For a more detailed description of the Change in Control Severance Plan, please refer to our Current Report on Form 8-K filed on July 26, 2019.

Legal

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

Note 10. Equity

Common Units

At December 31, 2019 and 2018, the Partnership's equity consisted of 1,541,215 and 1,521,806 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, 2019, cash distributions to our common units continued to be indefinitely suspended. Our credit agreement stipulates written consent from our lenders is required in order to reinstate common unit distributions. Management and the Board will continue to evaluate, on a quarterly basis, the appropriate level of cash reserves in determining future distributions. The suspension of common unit cash distributions is designed to preserve liquidity and reallocate excess cash flow towards capital expenditure projects and debt reduction to maximize long-term value for our unitholders. There is no assurance as to future cash distributions since they are dependent upon our projections for future earnings, cash flows, capital requirements, financial conditions and other factors.

Preferred Units

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

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

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

Class A Preferred Units

On August 11, 2016, we completed a private placement of 11,627,906 Class A Preferred Units for an aggregate offering price of $25.0 million. The Class A Preferred Units were issued at a price of $2.15 per Class A Preferred Unit. Proceeds from this issuance were used to fund an acquisition and for general partnership purposes, including the reduction of borrowings under our revolving credit facility. We received net proceeds of $24.6 million in connection with the issuance of these Class A Preferred Units. We allocated these net proceeds, on a relative fair value basis, to the Class A Preferred Units ($18.6 million) and the beneficial conversion feature ($6.0 million). Accretion of the beneficial conversion feature was $1.2 million for the years ended December 31, 2019 and 2018. 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, 2019, the Partnership had accrued $0.5 million for the fourth quarter 2019 distributions that will be paid in cash in February 2020. The following table summarizes cash distributions paid on our Class A Preferred Units during the year ended December 31, 2019:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2019	October 1, 2018 - December 31, 2018	$ 0.0430	$ 500
May 14, 2019	January 1, 2019 - March 31, 2019	$ 0.0430	$ 500
August 14, 2019	April 1, 2019 - June 30, 2019	$ 0.0430	$ 500
November 14, 2019	July 1, 2019 - September 30, 2019	$ 0.0430	$ 500

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

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 years ended December 31, 2019 and 2018. The registration statement registering resales of common units issued or to be issued upon conversion of the Class B Preferred Units was declared effective by the SEC on May 25, 2018.

At December 31, 2019, the Partnership had accrued $0.3 million for the fourth quarter 2019 distribution that will be paid in cash in February 2020. The following table summarizes cash distributions paid on our Class B Preferred Units during the year ended December 31, 2019:

Date Paid	Period Covered	Distribution per Unit	Total Distributions (in thousands)
February 14, 2019	October 1, 2018 - December 31, 2018	$ 0.0306	$ 300
May 14, 2019	January 1, 2019 - March 31, 2019	$ 0.0306	$ 300
August 14, 2019	April 1, 2019 - June 30, 2019	$ 0.0306	$ 300
November 14, 2019	July 1, 2019 - September 30, 2019	$ 0.0306	$ 300

The following table summarizes cash distributions paid on our Class B Preferred Units during the year 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. 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 are 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 are included in G&A in our consolidated statements of operations.

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

(in thousands)	Year Ended December 31, 2019	Year Ended December 31, 2018
Services agreement	$ 3,556	$ 2,685
Operating agreements	11,151	8,849
Oilfield services	6,213	3,941
Other agreements	320	310
Total	$ 21,240	$ 15,785

At December 31, 2019, we had a net payable to our affiliate, Mid-Con Energy Operating, of $6.9 million, comprised of a joint interest billing payable of $7.8 million and a payable for operating services and other miscellaneous items of $0.8 million, offset by an oil and natural gas revenue receivable of $1.7 million. At December 31, 2018, we had a net payable to our affiliate Mid-Con Energy Operating of $3.7 million, comprised of a joint interest billing payable of $3.7 million and a payable for operating services and other miscellaneous items of $1.2 million, offset by an oil and natural gas revenue receivable of $1.2 million. These amounts were included in accounts payable-related parties in our 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, 2019, sales of oil and natural gas to three purchasers accounted for approximately 76% of our sales. At December 31, 2019, these purchasers accounted for approximately 89% of our outstanding oil and natural gas accounts receivable. For the year ended December 31, 2018, sales of oil and natural gas to three purchasers accounted for approximately 83% of our sales. At December 31, 2018, these purchasers accounted for approximately 89% 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 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. Leases

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

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

A summary of our leases is presented below:

(in thousands)	Classification	Year Ended December 31, 2019	2018
Assets			
Operating	Other property and equipment	$ 835	$ —
Total lease assets		$ 835	$ —
Liabilities			
Current operating	Other current liabilities	$ 430	$ —
Non-current operating	Other long-term liabilities	457	—
Total lease liabilities		$ 887	$ —

	Classification	Year Ended December 31, 2019	2018
Operating lease expense(1)(2) (in thousands)	G&A expense	$ 259	$ 257
Weighted average remaining lease term (months)			
Operating leases		23	36
Weighted average discount rate			
Operating leases		5.7%	(3)

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

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

(in thousands)	Operating Leases
2020	$ 489
2021	471
Total lease maturities	960
Less: interest	73
Present value of lease liabilities	$ 887

Note 16. Subsequent Events

Land Sale

On January 23, 2020, we closed the sale of land in Southern Oklahoma, classified as held for sale at December 31, 2019, for a net cash settlement of $0.4 million.

Equity Awards

On January 29, 2020, the Board authorized the issuance of 1,633 unrestricted common units to replace unvested units to certain employees terminated during a reduction-in-force.

Appointment and Departure of Certain Officers and Directors

On January 30, 2020, the Partnership announced that Jeffrey R. Olmstead, President and Chief Executive Officer and Director of the general partner, was taking a three-month paid sabbatical commencing on February 1, 2020. Charles R. “Randy” Olmstead, Executive Chairman of the Board, was appointed as Chief Executive Officer of the general partner, and Chad B. Roller, PhD, was appointed as President of the general partner. Dr. Roller was previously appointed as Chief Operating Officer of the general partner effective July 24, 2019.

Preferred Unit 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, 2020, to holders of record as of the close of business on February 7, 2020.

Reverse Stock Split

On March 3, 2020, the Partnership announced that the Board has approved a 1-for-10 reverse unit split on the Partnership's common units, to become effective after the market closes on March 23, 2020.

Note 17. 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, 2019	2018
Property acquisition costs		
Proved	$ 3,167	$ 20,158
Unproved	164	1,085
Exploration	—	—
Development	13,868	8,617
Asset retirement obligations	8,487	15,491
Total costs incurred	$ 25,686	$ 45,351

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, 2019 and 2018, 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, 2017	18,510	6,282	19,557
Revisions of previous estimates (1)	1,484	(1,045)	1,310
Extensions, discoveries and other additions (2)	72	—	72
Purchases of reserves in place (3)	4,968	1,713	5,253
Sales of reserves in place (4)	(133)	(172)	(162)
Production	(1,112)	(457)	(1,188)
As of December 31, 2018	23,789	6,321	24,842
Revisions of previous estimates (1)	690	(1,527)	436
Extensions, discoveries and other additions	—	—	—
Purchases of reserves in place (5)	5,347	1,161	5,541
Sales of reserves in place (5)	(3,704)	(1,058)	(3,880)
Production	(1,179)	(676)	(1,292)
As of December 31, 2019	24,943	4,221	25,647
Proved developed reserves			
December 31, 2018	17,634	6,059	18,643
December 31, 2019	19,213	3,965	19,874
Proved undeveloped reserves			
December 31, 2018	6,155	262	6,199
December 31, 2019	5,730	256	5,773

(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 one successful step out well in 2018.
(3) Represents the purchase of proved reserves as part of our Oklahoma and Wyoming acquisitions.
(4) Decrease due to the sale of several small properties in the Texas core area.
(5) Represents the purchase and sale of proved reserves as part of the Strategic Transaction.

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.

The increase in quantities of proved reserves from December 31, 2018, to December 31, 2019, was due in part to net upward revisions of 2,136 MBoe from certain recent results and development modifications, offset in part by commodity price decreases of 1,700 MBoe which decreased the economic lives of certain producing properties. The net upward revision is primarily the result of restoring production (reactivation of wells) from the acquired Oklahoma waterflood properties. During 2019, the acquisition of the Oklahoma waterflood properties resulted in a positive revision of 5,541 MBoe, and the divestiture of the Texas core area resulted in a decrease in proved reserves of 3,880 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, 2019 and 2018, 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)	**2019**	**2018**
Future cash inflows	$ 1,326,502	$ 1,494,349
Future production costs	(745,748)	(694,862)
Future development costs, including abandonment costs	(65,948)	(92,973)
Future net cash flow	514,806	706,514
10% discount for estimated timing of cash flow	(273,602)	(358,261)
Standardized measure of discounted cash flow	$ 241,204	$ 348,253

The prices utilized in calculating our total proved reserves were $55.69 and $65.56 per Bbl of oil and $2.58 and $3.10 per MMBtu of natural gas for December 31, 2019 and 2018, 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 $52.90 and $62.17 per Bbl of oil and $1.68 and $2.43 per Mcf of natural gas for December 31, 2019 and 2018, respectively. Adjusted natural gas price includes the sale of associated NGLs. During the years ended December 31, 2019 and 2018, 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:

(in thousands)	Year Ended December 31, 2019	2018
Standardized measure of discounted future net cash flow, beginning of year	$ 348,253	$ 207,213
Changes in the year resulting from:		
Sales, less production costs	(27,111)	(38,316)
Revisions of previous quantity estimates	5,691	24,035
Extensions, discoveries and improved recovery	—	2,398
Net change in prices and production costs	(113,400)	102,480
Net change in income taxes	—	—
Changes in estimated future development costs	(13,938)	4,534
Previously estimated development costs incurred during the year	14,947	8,428
Purchases of reserves in place	57,679	50,242
Sales of reserves in place	(61,715)	(2,714)
Accretion of discount	34,825	20,721
Timing differences and other	(4,027)	(30,768)
Standardized measure of discounted future net cash flow, end of year	$ 241,204	$ 348,253

Note 18. Reverse Unit Split

On April 9, 2020, the Partnership effected a 1-for-20 reverse common unit split. For presentation purposes, the consolidated financial statements and footnotes have been adjusted to reflect this reverse unit split as if it had occurred at the beginning of the periods presented.

PART III

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, 2019, 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. 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.

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.

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 175,700 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, 2020:

Plan category	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	13,669 (1)
Equity compensation plans not approved by security holders	—
Total	13,669

(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 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.

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, 2019 and 2018. 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	2019	$ 270,417	$ 95,000	$ 62,400	$ 4,956 (1)	$ 432,773
President, CEO and Director(2)	2018	$ 257,633	$ 29,000	$ 105,000	$ 4,869 (1)	$ 396,502
Charles R. Olmstead	2019	$ 198,000	$ 80,500	$ 62,400	$ 4,620 (1)	$ 345,520
Executive Chairman of the Board(2)	2018	$ 198,000	$ 25,000	$ 105,000	$ 4,537 (1)	$ 332,537
Charles L. McLawhorn III	2019	$ 158,808	$ 58,446	$ 46,800	$ 4,956 (1)	$ 269,010
VP, General Counsel and Secretary	2018	$ 150,942	$ 17,400	$ 78,750	$ 4,701 (1)	$ 251,793

(1) Includes Registrant's contributions to a defined contribution plan.
(2) Mr. Jeffrey R. Olmstead began a three-month sabbatical on February 1, 2020. Mr. Charles R. Olmstead was appointed Chief Executive Officer and Mr. Chad B. Roller, PhD, was appointed President commencing on February 1, 2020.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2019:

Name	Number of Units That Have Not Yet Vested	Market Value of Units That Have Not Yet Vested (1)
Jeffrey R. Olmstead	3,000 (2)	$ 16,800
Charles R. Olmstead	3,000 (2)	$ 16,800
Charles L. McLawhorn III	2,250 (2)	$ 12,600

(1)Based on the closing price of our common units at December 31, 2019.
(2) These equity-settled phantom units vest equally on January 31, 2020, March 1, 2020 and January 31, 2021.

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

Employment Agreements

Our general partner has entered into employment agreements with Charles R. Olmstead and Jeffrey R. Olmstead. The following 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.

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. For the definitions of cause and good reason, and other terms of the agreement, please refer to the terms of the Employee Agreements dated August 1, 2011, filed with the SEC on December 23, 2011.

Change in Control Severance Plan

On July 24, 2019, the Board adopted the Mid-Con Energy Partners, LP Change in Control Severance Plan (the "CIC Severance Plan"), effective as of August 1, 2019. The CIC Severance Plan provides severance benefits to certain key management and employees of our general partner and its affiliates, including us, who are selected by the Plan Administrator (as defined in the CIC Severance Plan) and have entered into a Participation and Restrictive Covenant Agreement (which contains certain restrictive covenants being agreed to as a condition of participation), and whose employment is terminated (i) by our general partner without Cause (as defined in the CIC Severance Plan) or by the participant due to Good Reason (as defined in the CIC Severance Plan), in each case, within 24 months following the consummation of a Change in Control (as defined in the CIC Severance Plan) or (ii) by our general partner without Cause in anticipation of a Change in Control transaction that the Board is considering and that is ultimately consummated within six months of the participant's termination of employment (a "Qualifying Termination"). Each of our named executive officers was designated as a participant under the CIC Severance Plan.

If a participating executive officer's employment terminates in a Qualifying Termination, he or she will receive the following severance benefits:

(i) an amount equal to 36 multiplied by the sum of (x) such participant's monthly base salary in effect immediately prior to a Qualifying Termination (or prior to any reduction for purposes of Good Reason) and (y) 1/12 of such participant's target annual cash bonus for the calendar year in which the Qualifying Termination occurs;

(ii) any accrued, but unpaid as of the date of the Qualifying Termination, annual cash bonus for any completed fiscal year preceding a Qualifying Termination;

(iii) accrued benefits under any Retirement Plan or Welfare Plan (each as defined in the CIC Severance Plan); and

(iv) if the participant timely elects COBRA continuation coverage, reimbursement equal to the difference between the cost of such COBRA continuation coverage and the amount active employees pay for health coverage through the earlier of the end of the "Severance Period" and the participant becoming eligible for health insurance coverage under another employer's plan. The Severance Period is 36 months for the executive officers.

In the event a participant holds any equity awards granted under our Long-Term Incentive Program, the treatment of such equity awards in the event of a Qualifying Termination shall continue to be governed by the terms of the Long-Term Incentive Program and the applicable award agreements.

If any payments and benefits to be paid or provided to a participating executive officer, whether pursuant to the terms of the CIC Severance Plan or otherwise, would be subject to "golden parachute" excise taxes under the Internal Revenue Code, the payments and benefits will be reduced to the extent necessary to avoid such excise taxes, but only if such a reduction of pay or benefits would result in a greater after-tax benefit to the eligible employee.

For the terms of the CIC Severance Plan, including but not limited to definitions of Good Reason, Cause and Change in Control, please refer to the CIC Severance Plan included as Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on July 26, 2019.

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 2019, 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, 2019:

Name (1)	Fee Earned or Paid in Cash	Unit Awards (2)	Total
C. Fred Ball Jr.	$ 71,000	$ 10,400	$ 81,400
John W. Brown	$ 66,000	$ 10,400	$ 76,400
Wilkie S. Colyer Jr.	$ 34,000	$ 10,400	$ 44,400
Peter A. Leidel	$ 34,000	$ 10,400	$ 44,400
Cameron O. Smith	$ 71,000	$ 10,400	$ 81,400

(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 500 units granted to each board member in January 2019. There were no awards outstanding at fiscal year-end.

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

As of March 3, 2020, 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)	185,733	11.9%	930,223	8.0%	522,875	5.3%
John C. Goff(4)	33,900	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)	149,283	9.6%	232,558	2.0%	—	—%
Charles R. Olmstead(8)(9)	43,709	2.8%	—	—%	—	—%
Jeffrey R. Olmstead(8)(10)	29,621	1.9%	—	—%	—	—%
Charles L. McLawhorn III(8)	4,177	*	—	—%	—	—%
C. Fred Ball Jr.(8)(11)	5,566	*	—	—%	—	—%
Peter A. Leidel(8)(12)	23,147	1.5%	—	—%	—	—%
Cameron O. Smith(8)	3,367	*	—	—%	—	—%
Wilkie S. Colyer Jr.(8)(13)	1,200	*	116,279	1.0%	196,078	2.0%
John W. Brown(8)	2,000	*	—	—%	—	—%
All named executive officers, directors and director nominees as a group (11 people)(14)	128,911	8.3%	116,279	1.0%	196,078	2.0%

* 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 within sixty days. As of March 3, 2020, 1,557,848 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 its Preferred Units into common units, Mid-Con Energy III, LLC would be deemed to beneficially own, directly or indirectly, 258,388 common units or 15.8% 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) 8,000 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, 737,487 common units or 32.6% 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, 93,023 common units or 5.6% 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, 81,395 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, 160,911 common units or 10.3% 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.

(9) Includes 25,000 common units held by the Mardeen A. Olmstead Revocable Living Trust for which Mr. Olmstead serves as co-trustee. Mr. Olmstead disclaims beneficial ownership of these units except to the extent of his pecuniary interest therein.

(10) Includes 5,635 common units held by the Charles R. Olmstead 2011 Trust that has immediate family members who are beneficiaries of the trust for which Mr. Olmstead serves as trustee. Mr. Olmstead disclaims beneficial ownership of these units except to the extent of his pecuniary interest therein.

(11) Includes 200 common units held by the Charles F. Ball, Jr. IRA for which Mr. Ball is the beneficiary and 100 common units held by the Charlotte I. Ball IRA for which Mr. Ball’s spouse is the beneficiary. Mr. Ball disclaims beneficial ownership to the units held by the Charlotte I. Ball IRA except to the extent of his pecuniary interest therein.

(12) Includes (i) 10,821 common units held by The Peter A. Leidel, 2015 GRAT for which Mr. Leidel is the sole trustee and beneficiary; (ii) 1,860 common units held by Yorktown Energy Partners, VII, L.P. for which Mr. Leidel is a member and manager of Yorktown VII Associates LLC, the general partner of Yorktown Company LP, the general partner of Yorktown Energy Partners VII, L.P.; and (iii) 7,022 common units held by Yorktown Energy Partners VI, L.P. for which Mr. Leidel is a member and manager of Yorktown VI Associates LLC, the general partner of Yorktown VI Company LP, the general partner of Yorktown Energy Partners VI, L.P. Mr. Leidel disclaims beneficial ownership of the 1,860 common units and 7,022 common units except to the extent of his pecuniary interest therein.

(13) Includes (i) 23,256 Class A convertible preferred units held by Goff MCEP Holdings but are held for the benefit of Mr. Colyer pursuant to an understanding between Mr. Colyer and Goff MCEP Holdings; Mr. Colyer is a principal of Goff Capital, which is the manager of Goff MCEP Holdings; Mr. Colyer and Goff Capital disclaim beneficial ownership of these units except to the extent of their respective pecuniary interest therein; (ii) 93,023 Class A convertible preferred units held by Goff MCEP Holdings but are held for the benefit of Colyer Interests, LLC (“Colyer Interests”), of which Mr. Colyer is the Managing Member, pursuant to an understanding between Colyer Interests and Goff MCEP Holdings; Mr. Colyer is a principal of Goff Capital, which is the manager of Goff MCEP Holdings; Mr. Colyer, Goff Capital and Colyer Interests each disclaim beneficial ownership of these units except to the extent of their pecuniary interest therein; (iii) 65,359 Class B convertible preferred units held by Goff MCEP II but are held for the benefit of Mr. Colyer pursuant to an understanding between Mr. Colyer and Goff MCEP II; Mr. Colyer is the Senior Vice President/Investments of GFS MCEP, which is the general partner of Goff MCEP II; Mr. Colyer and GFS MCEP each disclaim beneficial ownership of these units except to the extent of their

respective pecuniary interest therein; and (iv) 130,719 Class B convertible preferred units held by Goff MCEP II but are held for the benefit of Colyer Interests, of which Mr. Colyer is the Managing Member, pursuant to an understanding between Mr. Colyer and Goff MCEP II; Mr. Colyer is the Senior Vice President/Investments of GFS MCEP, which is the general partner of Goff MCEP II; Mr. Colyer, Colyer Interests and GFS MCEP each disclaim beneficial ownership of these units except to the extent of their respective pecuniary interest therein. If Mr. Colyer converted all of his Preferred Unit into common units, Mr. Colyer would be deemed to beneficially own, directly or indirectly, 16,818 common units or 1.1% of the common units outstanding.

(14) If Mr. Colyer converted all of his Preferred Unit into common units, the named executive officers and directors would be deemed to beneficially own, directly or indirectly, 144,529 common units or 9.2% of the common units outstanding.

As of March 3, 2020, our general partner owned a 1.1% limited partnership interest in us. 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."

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.

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.