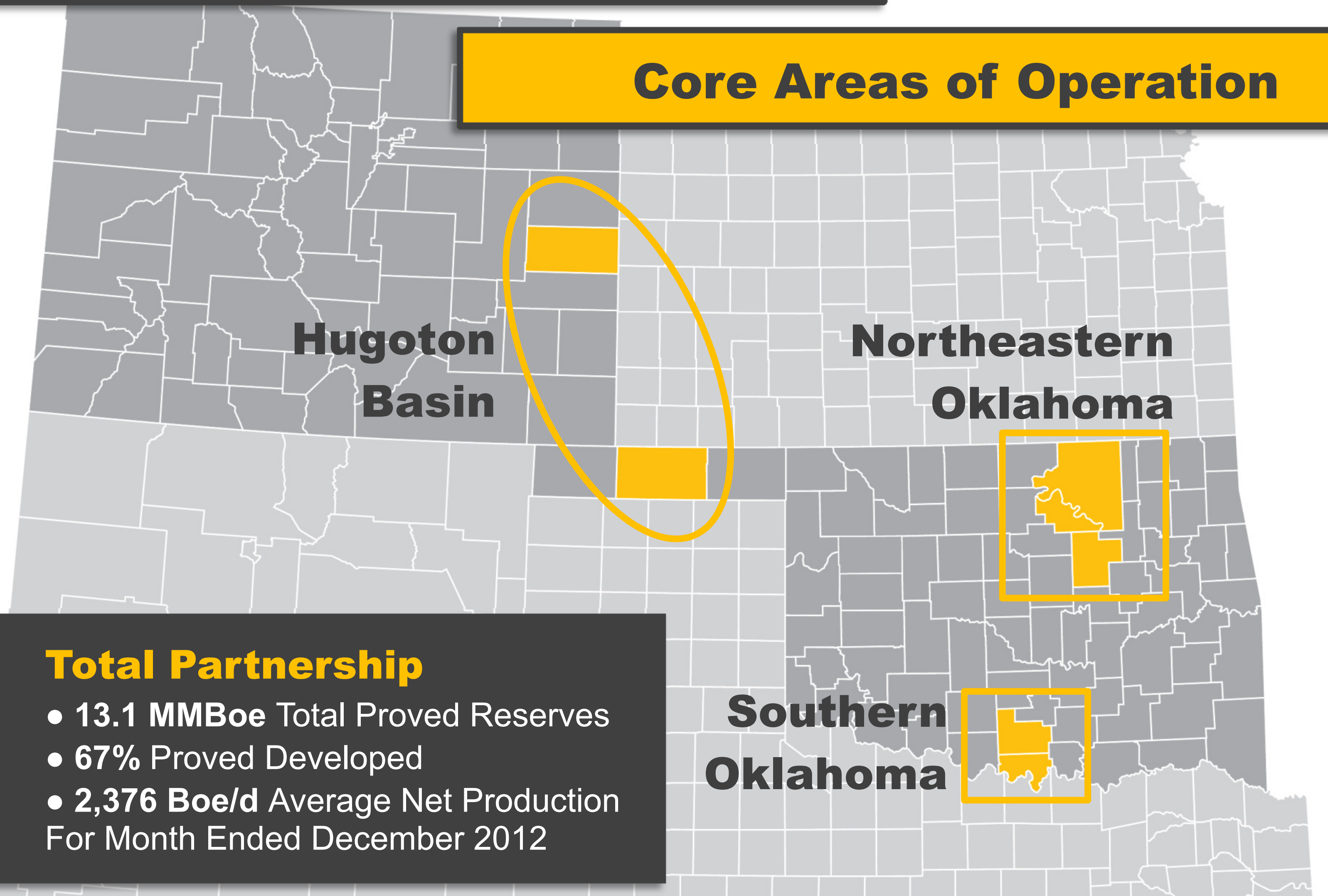
Mid-Con Energy Partners, LP
2012 Annual Report

MCEP
NASDAQ
LISTED

Mid-Con Energy Partners, LP

Core Areas of Operation



Total Partnership

- **13.1 MMBoe** Total Proved Reserves
- **67%** Proved Developed
- **2,376 Boe/d** Average Net Production For Month Ended December 2012

Southern Oklahoma

- **6.7 MMBoe** Total Proved Reserves
- **56%** Proved Developed
- **1,374 Boe/d** Average Net Production For Month Ended December 2012

Northeastern Oklahoma

- **3.1 MMBoe** Total Proved Reserves
- **69%** Proved Developed
- **414 Boe/d** Average Net Production For Month Ended December 2012

Hugoton Basin

- **3.1 MMBoe** Total Proved Reserves
- **87%** Proved Developed
- **556 Boe/d** Average Net Production For Month Ended December 2012

Other

- **0.2 MMBoe** Total Proved Reserves
- **100%** Proved Developed
- **32 Boe/d** Average Net Production For Month Ended December 2012

Mid-Con Energy Partners, LP is a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Mid-Con Energy's core areas of operation are located in Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin.

Dear Fellow Unitholders:

Prior to completing our initial public offering in December 2011, we spent much time planning and preparing our team for what to expect as a public entity. With our primary business objective at the forefront, Mid-Con Energy Partners, LP (“Mid-Con Energy”) was established for the purposes of growing reserves and production, generating stable cash flows, making cash distributions to our unitholders, and over time, increasing those distributions. Acknowledging this was a recurring theme among upstream MLPs, we set out to differentiate ourselves through the assets that we operated, the quality of our acquisitions, the timeliness and transparency of our reporting, and the total return that we hoped to provide to our unitholders. Based on these factors, we are pleased to say that 2012 was a success.

Waterflooding is our core strategy. It has proven to be successful for us from a production and reserve growth standpoint and especially rewarding in an oil-favored commodity price environment. While our net proved reserves at December 31, 2012 of 13.1 MMBoe increased 31% over the prior year, two significant metrics were unchanged – Mid-Con Energy is 99% oil and 99% operated – on a Boe basis. This favorable commodity mix and operational influence allow us to maximize the value of our producing properties and afford us substantial control over the timing and costs of our operations.

In 2012, we drilled 39 gross (30 net) development wells, primarily in our Southern and Northeastern Oklahoma core areas. As a result, our average net production for 2012 was 1,907 Boe/d, which was an increase of approximately 60% from our average net production for 2011 of 1,191 Boe/d. Our existing reserve portfolio includes waterflood projects at various stages of maturity and therefore, each contains varying prospects for organic growth. We expect to realize this potential growth through increased injection and continued development, which will allow us to capture additional quantities of recoverable oil in place.

Significant gains in production and favorable oil pricing translated into a record year for Mid-Con Energy in terms of cash flow generation. Adjusted EBITDA for 2012 was $47.7 million, representing a 99% increase above Adjusted EBITDA for 2011 of $24.0 million.

We have a multifaceted approach to acquiring new, high-quality properties. While there remains the potential for drop-down opportunities from our private affiliates, in 2012 we demonstrated our ability to identify and execute bolt-on acquisitions from third parties that fit our waterflood strategy. We closed four acquisitions in 2012, representing approximately 442 Boe/d in average net production and $49 million in total transaction value. Approximately 41% of these acquisitions, as a percentage of total transaction value, were related to acquiring additional working interests within existing Mid-Con Energy waterflood projects. The remaining 59% of transaction value was related to the acquisition of a new waterflood project located five miles southeast of our properties in the Hugoton Basin core area.

Ultimately, our unitholders share in the tangible success of our properties through quarterly cash distributions. We are pleased to report that in our first full year as a publicly traded partnership, Mid-Con Energy increased its quarterly distribution rate approximately 4% to $0.495 per unit, or $1.98 on an annualized basis.

We experienced accomplishments in 2012 that would not have been possible without sound execution by our staff. Their diligence and expertise are the core of what we value as a partnership, and their continued efforts will be essential to our future growth.

In 2013, we will strive to remain true to our founding purposes: to grow reserves and production, generate stable cash flows, make cash distributions to our unitholders and, over time, to increase those distributions. As always, your investment in us is greatly appreciated and we thank you for your support.

Sincere Regards,

The Founders of Mid-Con Energy GP, LLC

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

Form 10–K

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

For the fiscal year ended December 31, 2012

OR

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

Commission File No.: 1-35374

Mid-Con Energy Partners, LP
(Exact name of registrant as specified in its charter)

Delaware	45–2842469
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2501 North Harwood Street, Suite 2410
Dallas, Texas 75201
(Address of principal executive offices and zip code)

(972) 479-5980
(Registrant's telephone number, including area code)

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b–2 of the Exchange Act. Check one:

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐	Smaller reporting company ☐

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

The aggregate market value of the common units held by non-affiliates of the registrant was approximately $148.2 million on June 30, 2012, based on $20.28 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

Documents incorporated by Reference: None.

As of March 6, 2013 the registrant had 19,230,350 common units and 360,000 general partner units outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following includes a description of the meanings of some of the oil and gas industry terms used throughout this report. 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.

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

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

Bbl/d: One Bbl per day.

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

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

Boe/d: One Boe per day.

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

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

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

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

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

EPA: United States Environmental Protection Agency.

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

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

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

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

MBbls: One thousand Bbls.

MBoe: One thousand Boe.

MBtu: One thousand Btu.

MBoe/d: One thousand Boe per day.

Mcf: One thousand cubic feet of natural gas.

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

MMBoe: One million Boe.

MMBtu: One million Btu.

MMcf: One million cubic feet of natural gas.

NGLs: Natural gas liquids.

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

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

NYMEX: New York Mercantile Exchange.

Oil: Oil, condensate and natural gas liquids.

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 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 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, LKH, 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, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. 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: 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 are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should 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 tests in the area and in the same reservoir.

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

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

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

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

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 Securities and Exchange Commission (“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.

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

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

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

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

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

WTI: West Texas Intermediate, also called Texas light sweet, is defined as a type of crude oil as a benchmark in oil price and is the underlying commodity of New York Mercantile Exchanges oil future contracts.

NAMES OF ENTITIES

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

- *"Founders" collectively refers to Charles R. Olmstead, S. Craig George and Jeffrey R. Olmstead;*
- *"our general partner" refers to Mid-Con Energy GP, LLC;*
- *"Mid-Con Affiliates" collectively refers to Mid-Con Energy III, LLC and Mid-Con Energy IV, LLC, which are affiliates of our general partner;*
- *"Mid-Con Energy Partners," the "partnership," "we," "our," "us" 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, Inc., an affiliate of our general partner;*
- *"Mid-Con Energy Properties" refers to Mid-Con Energy Properties, LLC, our wholly owned subsidiary;*
- *"our predecessor" collectively refers to Mid-Con Energy Corporation, prior to June 30, 2009, and to Mid-Con Energy I, LLC and Mid-Con Energy II, LLC, on a combined basis, thereafter, our respective predecessors for accounting purposes; and*
- *"Yorktown" collectively refers to Yorktown Partners LLC, Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., Yorktown Energy Partners VIII, L.P. and/or Yorktown Energy Partners IX, L.P.*

FORWARD-LOOKING STATEMENTS

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

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

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. "Business," Item 1A. "Risk Factors," Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," "goal," "forecast," "guidance," "might," "scheduled" and the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the forward-looking events will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in the "Risk Factors" section and elsewhere in this Annual Report on Form 10-K. All forward-looking statements speak only as of the date made, and other than as required by law. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

ITEM 1. BUSINESS

We are a Delaware limited partnership formed in July 2011 that engages in the acquisition, exploitation and development of producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company.

In connection with our initial public offering in December 2011, our predecessors, Mid-Con Energy I, LLC and Mid-Con Energy II, LLC, merged into our wholly owned subsidiary, Mid-Con Energy Properties.

Our common units are traded on the NASDAQ Global Select Market under the symbol "MCEP". Our business activities are primarily conducted through Mid-Con Energy Properties.

Overview

We operate as one business segment engaged in the exploration, development and production of oil and natural gas properties. Our properties are located in the Mid-Continent region of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

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

As of December 31, 2012, our total estimated proved reserves were approximately 13.1 MMBoe, of which approximately 99% were oil and 67% were proved developed, both on a Boe basis. As of December 31, 2012, we operated 99% of our properties through our affiliate, Mid-Con Energy Operating and 99% of our properties were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended December 31, 2012 was approximately 2,376 Boe per day and our total estimated proved reserves had an average reserve-to-production ratio of approximately 15 years. Our management team developed approximately 53% of our total proved reserves through new waterflood projects.

The following table summarizes information by core area regarding our estimated proved oil and natural gas reserves, and our average net production for the month ended December 31, 2012.

	Estimated Net Proved Reserves				December 2012 Average Net Production		Reserve-to-	Gross Active Wells		
	(MBoe)	% Operated (1)	% Oil	% Proved Developed	Boe/d Gross	Boe/d Net	Production Ratio (2)	Oil and Natural Gas Wells	Injection Wells	Shut-in/ Waiting on Completion
Southern Oklahoma	6,668	100%	100%	56%	2,802	1,373	13	87	57	6
Northeastern Oklahoma	3,125	100%	99%	69%	717	415	21	214	71	32
Hugoton Basin	3,137	100%	100%	87%	658	556	16	51	23	29
Other	216	97%	97%	100%	77	32	18	13	4	2
Total	13,146	99%	99%	67%	4,254	2,376	15	365	155	69

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

(2) The reserve to production ratio is calculated by dividing estimated net proved reserves as of December 31, 2012 by average net production for the month ended December 31, 2012.

Developments in 2012

Acquisitions

During June 2012, we acquired properties in the Northeastern Oklahoma area and additional working interests in our existing units in the Southern Oklahoma area for approximately $16.4 million in separate transactions, subject to customary purchase price adjustments.

During October and November 2012, we acquired properties and additional working interests in the Hugoton Basin area for approximately $32.6 million in separate transactions, subject to customary purchase price adjustments. Included in these transactions was the acquisition of the Clawson Ranch Waterflood Unit on November 2, 2012, from multiple parties for 100% of the working interests, located in Texas County, Oklahoma for approximately $28.9 million in cash, subject to customary purchase price adjustments.

Public Offering of Additional Units

On October 22, 2012, we and Yorktown sold an aggregate of 4,600,000 common units to the public at a price of $21.20 per common unit. 1,000,000 common units were sold by us, and 3,600,000 common units were sold by Yorktown.

We used the net proceeds of approximately $20.4 million from our 1,000,000 common units offering, after deducting underwriting discounts but before offering expenses, to repay borrowings outstanding under our credit facility. We did not receive any proceeds from the 3,600,000 common units sold by Yorktown.

Other

During April 2012, the borrowing base under our credit facility was increased from $75.0 million to $100.0 million and Wells Fargo Bank, N.A. was added as an additional lender. No other material terms of the original credit agreement were amended.

During November 2012, the borrowing base under our credit facility was increased from $100.0 million to $130.0 million and Comerica Bank was added as an additional lender. No other material terms of the original credit agreement were amended.

Our Business Strategies

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

- ***Continue exploitation of our existing properties to maximize production.*** We plan to continue exploiting our proved reserves to maximize production, primarily through waterflood projects and through various oil recovery methods, including workovers, conventional hydraulic fracturing, re-stimulations, recompletions, infill drilling and other optimization activities. Using these techniques, we significantly increased our average net production over the twelve months ended December 31, 2012. We expect to continue these activities in order to maximize our production.
- ***Pursue acquisitions of long-lived, low-risk producing properties with upside potential.*** We will seek to acquire onshore properties with long-lived reserves, low production decline rates and low-risk development potential. We also will seek to acquire properties within mature oil fields with opportunities for incremental improvements in oil recovery through waterfloods and other recovery techniques, which we believe will offer us additional potential to increase reserves, production and cash flow.

- ***Capitalize on our relationship with the Mid-Con Affiliates for favorable acquisition opportunities.*** We expect that the Mid-Con Affiliates will invest capital and technical staff resources to acquire and develop properties with existing waterfloods and to identify, acquire, form and develop new waterflood projects on those properties. Through this relationship with the Mid-Con Affiliates, we plan to avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing them, we expect that the Mid-Con Affiliates will offer to sell properties to us from time to time. We believe that the opportunity to acquire properties from the Mid-Con Affiliates provides us with a strategic advantage over those of our competitors who must bear a greater share of development risks themselves.
- ***Maintain operational control and a focus on cost-effectiveness in all our operations.*** As of December 31, 2012, Mid-Con Energy Operating operated 99% of our properties, as calculated on a Boe basis. We plan to continue exercising this level of operational control over our existing properties and favor acquisitions of operated properties in order to manage the timing and levels of our capital expenditures, development activities and operating costs.
- ***Reduce the impact of commodity price volatility on our cash flow through a disciplined commodity hedging strategy.*** We seek to reduce the impact of commodity price volatility on our cash flow by maintaining a portfolio of hedge contracts to help protect our ability to make distributions. As opposed to entering into commodity derivative contracts at predetermined times or on prescribed terms, we intend to enter into commodity derivative contracts in connection with material increases in our estimated production and at times when we believe market conditions or other circumstances suggest that it is prudent to do so. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes or the duration of our hedge contracts when circumstances suggest that it is prudent to do so.
- ***Maintain a balanced capital structure to allow for financial flexibility to execute our business strategies.*** We intend to maintain a balanced capital structure that affords us the financial flexibility to execute our business strategies. Our borrowing capacity under our credit facility, our access to capital markets and internally generated cash flow provides us with the liquidity and financial flexibility to exploit organic growth opportunities and allow us to pursue additional acquisitions of producing properties.
- ***Utilize compensation programs that align the interest of our management team with our unitholders.*** We tie the compensation of our executives and directors directly to achieving our strategic, operating and financial goals and have adopted compensation programs that place a significant part of the pay of each of our executives "at risk" in the form of an annual short-term incentive award and long-term, equity-based incentive grants. The amount of the annual short-term incentive award paid depends on our performance against financial and operating objectives as well as the executive meeting key leadership and development standards. A portion of the compensation of the executives is also in the form of equity awards that tie their compensation directly to creating unitholder value over the long-term. We believe this combination of annual short-term incentive awards and long-term equity awards aligns the incentives of our management with our unitholders.

Our Competitive Strengths

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

- ***An asset portfolio largely consisting of properties with existing waterflood projects with proved reserves, of which 99% are oil, and relatively predictable production profiles that provide growth potential through ongoing response to waterflooding and that have modest capital requirements.*** Our properties consist of interests in mature fields located in Oklahoma and Colorado that have well-understood geologic features, relatively predictable production profiles and modest capital requirements, which we believe make them well-suited for waterflood development and for our objective of generating stable cash flow. Over 99% of our properties are being waterflooded and over 91% have been producing continuously since 1982 or earlier. Based on production estimates from our December 31, 2012 audited reserves, the average estimated decline rate for our existing proved developed producing reserves is approximately 20% for 2013 and, on a compounded average decline basis, approximately 13% for the subsequent five years and approximately 10% thereafter. Further, we believe that a substantial majority of the capital required for growth from our existing properties has already been spent. As a result, these properties have relatively predictable production profiles and production growth potential with modest capital requirements.

- ***The ability to further exploit existing mature properties by utilizing our waterflood expertise.*** Our management team has actively operated most of our properties since 2005, and has a history of exploiting proved reserves to maximize production, primarily through waterflood projects. Over the last eight years, we identified, initiated, acquired, formed and developed over 25% of all new waterflood projects in the State of Oklahoma, while the next most active competitor formed only 7% of all new waterfloods. Furthermore, our experience in the Mid-Continent allows us to exploit synergies developed by applying knowledge of field, reservoir and play characteristics across the region. We believe that our expertise in secondary recovery techniques will increase the level of production from certain of our properties, particularly from existing waterflood projects, which, over time, may increase our cash flow.
- ***Acquisition opportunities that are consistent with our criteria of predictable production profiles with upside potential that may arise as a result of our relationship with the Mid-Con Affiliates.*** We expect the Mid-Con Affiliates to invest capital and technical staff resources to acquire and develop properties with existing projects and to identify, acquire, form and develop new waterflood projects on their properties. While they are not obligated to sell any properties to us and may have difficulties acquiring and developing them, we expect that the Mid-Con Affiliates will offer to sell properties to us from time to time. Through this relationship with the Mid-Con Affiliates, we avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire.
- ***Access to the collective expertise of Yorktown's employees and their extensive network of industry relationships through our relationship with Yorktown.*** Yorktown is a private investment firm focused on investments in the energy sector with more than $3.0 billion in assets under management. As of December 31, 2012, Yorktown owned a 26.9% limited partner interest in us, making it our largest unitholder, and Yorktown Energy Partners, IX, L.P., owned a 50% interest in our affiliate, Mid-Con Energy Operating. With their extensive investment experience in the oil and natural gas industry and their extensive network of industry relationships, Yorktown's employees are well positioned to assist us in identifying and evaluating acquisition opportunities and in making strategic decisions.
- ***Mid-Con Energy Operating operates 99% of our properties, which allows them to control our operating costs and capital expenditures***. As of December 31, 2012, Mid-Con Energy Operating operated 99% of our properties, as calculated on a Boe basis, which allowed it to control our operating costs and capital expenditures. We expect to continue exercising this level of operational control over our properties, including any properties we acquire through future acquisitions, which allows us to better manage our operating costs and capital expenditures. This substantial operational control of our producing properties also allows us to maximize the value of our properties, helps us stabilize our cash flow and affords us better control over the timing and costs of our operations.
- ***An enhanced ability to pursue acquisition opportunities arising from our competitive cost of capital and balanced capital structure.*** Unlike our corporate competitors, we are not subject to federal income taxation at the entity level. This attribute should provide us with a lower cost of capital compared to those competitors, thereby enhancing our ability to compete for acquisitions of oil and, when advantageous, natural gas properties. Also our low level of indebtedness and our ability to issue additional common units and other partnership interests in connection with these acquisitions improves

our financial flexibility. As of December 31, 2012, we had an available borrowing capacity of $52.0 million under our credit facility after giving effect to our current borrowings of $78.0 million, providing us with other means of financing acquisition opportunities.

- ***The range and depth of our technical and operational expertise allows us to expand both geographically and operationally to achieve our goals.*** We have assembled a senior team of geologists, engineers, landmen, accountants and operational personnel that have been successful in developing a significant number of new waterflood projects. Collectively, our management and employees have prior waterflood experience in over 150 waterflood projects located in more than ten states. We have a team of over 65 employees, with senior leadership in all production disciplines, and we have recruited a select group of younger professionals that are being trained in our waterflood specialty. With this expertise and depth, we believe this team has the ability to generate new waterflood projects that may become future acquisition opportunities for us. Beyond our core strength of waterflood development, our range and depth of expertise will allow us to expand both geographically and operationally. Although our projects to date have been focused on waterfloods in the Mid-Continent region, our management and operational employees have significant oil and gas experience in many other regions of the United States. Our wealth of experience enables us to pursue other types of exploitation opportunities, such as infill drilling projects that could significantly contribute to our strategy of generating stable cash flow and, over time, increasing our quarterly cash distributions.

Hedging Strategy

Our hedging strategy seeks to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program's objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distribution over time, while retaining some ability to participate in upward movements in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher hedged percentage in the near 12 months of the period. As of December 31, 2012, we have commodity derivative contracts covering approximately 71% and 59% of our estimated average daily oil production for calendar years 2013 and 2014 (as estimated from the projection of our oil production in our audited proved reserves as of December 31, 2012). As of December 31, 2012 all of our derivative contracts for 2013 and 2014 are either swaps with fixed settlements or collars. The weighted average minimum prices on all of our derivative contracts for 2013 and 2014 are $98 and $93.71, respectively. A "collar" is a combination of a put option we purchase and a call option we sell. The put option portion of a collar is also referred to as a "floor." A floor establishes a minimum average sale price for future oil production.

As of March 6, 2013, we have commodity derivative contracts covering approximately 76%, 70% and 5% of our estimated average daily oil production for calendar years 2013, 2014 and 2015 (as estimated from the projection of our oil production in our audited proved reserves as of December 31, 2012). The weighted average minimum prices on all of our derivative contracts for 2013, 2014 and 2015 are $98.03, $93.56 and $90.05, respectively.

In addition to our primary hedging strategy as described above, we also intend to enter into additional commodity derivative contracts in connection with material increases in our estimated production and at times when we believe market conditions or other circumstances suggest that it is prudent to do so as opposed to entering into commodity derivative contracts at predetermined times or on prescribed terms. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes or the duration of our hedge contracts when circumstances suggest that it is prudent to do so.

By removing a significant portion of price volatility associated with our estimated future oil production, we have mitigated, but not eliminated, the potential effects of changing oil prices on our cash flow from operations for those periods. For a further description of our commodity derivative contracts, please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Derivative Contracts."

Our Principal Business Relationships

Our Relationship with the Mid-Con Affiliates

In June 2011, management and Yorktown formed two limited liability companies, which we refer to collectively as the Mid-Con Affiliates, to acquire and develop oil and natural gas properties that are either undeveloped or that may require significant capital investment and development efforts before they meet our criteria for ownership. As these development projects mature, we expect to have the opportunity to acquire certain of these properties from the Mid-Con Affiliates. Through this relationship with the Mid-Con Affiliates, we will avoid much of the capital, engineering and geological risks associated with the early development of any of these properties we may acquire. However, the Mid-Con Affiliates may not be successful in identifying or consummating acquisitions or in successfully developing the new properties they acquire. Further, the Mid-Con Affiliates are not obligated to sell any properties to us and they are not prohibited from competing with us to acquire oil and natural gas properties.

Services Agreement

In December 2011, our subsidiaries and our general partner entered into a services agreement with Mid-Con Energy Operating. Pursuant to the services agreement, Mid-Con Energy Operating provides certain services to us, our subsidiaries and our general partner, including management, administrative and operational services, which include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate back to us. Mid-Con Energy Operating will not be liable to us for its performance of, or failure to perform, services under the services agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Our Relationship with Yorktown

We have a valuable relationship with Yorktown, a private investment firm founded in 1991 and focused on investments in the energy sector. Since 2004, Yorktown has made several equity investments in our predecessor. As of December 31, 2012 Yorktown owned approximately a 26.9% limited partner interest in us, making it our largest unitholder. Yorktown Energy Partners IX, L.P., owns a 50% interest in our affiliate Mid-Con Energy Operating. Also, Peter A. Leidel, a principal of Yorktown, serves on our board of directors.

Yorktown currently has more than $3.0 billion in assets under management and Yorktown’s employees have extensive investment experience in the oil and natural gas industry. Yorktown’s employees review a large number of potential acquisitions and are involved in decisions relating to the acquisition and disposition of oil and natural gas assets by the various portfolio companies in which Yorktown owns interests. With their extensive investment experience in the oil and natural gas industry and their extensive network of industry relationships, Yorktown’s employees are well positioned to assist us in identifying and evaluating acquisition opportunities and in making strategic decisions. Yorktown is not obligated to sell any properties to us and they are not prohibited from competing with us to acquire oil and natural gas properties. Investment funds managed by Yorktown manage numerous other portfolio companies, including the Mid-Con Affiliates, that are engaged in the oil and natural gas industry and, as a result, Yorktown may present acquisition opportunities to other Yorktown portfolio companies that compete with us.

Our Areas of Operation

As of December 31, 2012, our properties were located in the Mid-Continent region of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. These core areas are each composed of multiple waterflood units that are in close proximity to one another, produce from the same or geologically similar reservoirs and use similar waterflood methods. Focusing on these core areas allows us to apply our cumulative technical and operational knowledge to ongoing property development and to better predict future rates of recovery. For a discussion of the properties in our core areas, please see "Summary of Oil Properties and Projects."

Our properties consist of mature, legacy onshore oil reservoirs, approximately 99% of the reserves of which are being produced under waterflooding, on a Boe basis. Our properties include multiple waterflood projects with varying degrees of maturity. We have staggered the waterflooding of these properties so that production increases from more recently developed waterfloods offset declines from mature waterflood areas, leading to more stable cash flow and product.

We own on average a 75% working interest across 365 gross producing (272 net) wells, 155 gross injection (107 net) wells, and 69 gross (61 net) wells shut-in or waiting on completion and operate 99% of our properties by value, as calculated using the standardized measure. Approximately 99% of our revenue is derived from the proceeds of oil production. Our estimated proved reserves as of December 31, 2012 were approximately 13.1 MMBoe, of which approximately 99% were oil and approximately 67% were proved developed, both on a Boe basis. For the month ended December 31, 2012, we produced an average of approximately 2,376 Boe per day.

The following table shows our estimated net proved oil reserves or principal fields, based on a reserve report prepared by our internal reserve engineers and audited by Cawley, Gillespie & Associates, Inc., our independent petroleum engineers, as of December 31, 2012, and certain unaudited information regarding production and sales of oil and natural gas with respect to such properties:

	Average Net Production For the Month Ended December 31, 2012		Estimated Net Proved Reserves as of December 31, 2012					
	Net (Boe/d)	**% of Total**	**MBoe**	**% of Total Proved Reserves**	**% Oil**	**% Proved Developed Reserves**	**PV –10 (2) (3) ($ in millions)**	**% of Total**
Southern Oklahoma								
Field / Units:								
Highlands (1)	547	23%	3,665	28%	100%	42%	$ 137	34%
Battle Springs (1)	248	10%	964	7%	100%	77%	$ 29	7%
Twin Forks (1)	503	21%	1,157	9%	99%	75%	$ 58	14%
Ardmore West (1)	26	1%	744	6%	98%	57%	$ 29	7%
Southeast Hewitt	36	2%	111	1%	100%	100%	$ 3	1%
Other Fields/Units	14	1%	27	0%	99%	100%	< $ 1	0%
Total Southern Oklahoma	1,374	58%	6,668	51%	99%	56%	$ 256	63%
Northeastern Oklahoma								
Fields / Units:								
Cleveland	269	11%	2,127	16%	99%	58%	$ 42	11%
Cushing	108	5%	689	5%	98%	100%	$ 17	4%
Skiatook (1)	31	1%	218	2%	100%	100%	$ 5	2%
Other Fields/Units	6	0%	91	1%	100%	32%	< $ 1	0%
Total Northeastern Oklahoma	414	17%	3,125	24%	99%	69%	$ 64	17%
Hugoton Fields / Units:								
War Party I (1)	122	5%	381	3%	99%	79%	$ 17	4%
War Party II (1)	98	4%	894	7%	99%	100%	$ 8	2%
Harker Ranch (1)	122	5%	208	2%	100%	100%	$ 9	2%
Clawson Ranch	214	9%	1,654	12%	100%	86%	$ 42	10%
Total Hugoton	556	23%	3,137	24%	100%	87%	$ 76	18%
Other Fields / Units:								
Decker (1)	19	1%	210	1%	100%	100%	$ 8	2%
Miscellaneous	13	1%	6	0%	0%	100%	< $ 1	0%
Total Other	32	2%	216	1%	97%	100%	$ 8	2%
All Fields	**2,376**	**100%**	**13,146**	**100%**	**99%**	**67%**	**$ 404**	**100%**

(1) Denotes a waterflood project or unit that we identified, acquired, formed and developed.

(2) Standardized measure is calculated in accordance with Financial Accounting Stantdards Board Accounting Standards Codification Topic 932, *Extractive Activiti*es—Oil and Gas. 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. For a description of our commodity derivative contracts, please read—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Derivative Contracts."

(3) Our estimated net proved reserves and standardized measure were computed by applying average trailing 12-month index prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable 12-month period, held constant throughout the life of the properties). These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The average trailing 12-month index prices were $94.71 per Bbl for oil and $2.752 per MMBtu for natural gas for the 12 months ended December 31, 2012.

All proved undeveloped locations conform to SEC rules for recording proved undeveloped reserves. None of our proved undeveloped reserves as of December 31, 2012 have remained undeveloped for more than five years from the date the reserves were initially booked as proved undeveloped.

Summary of Oil Properties and Projects

Our principal fields detailed below represent approximately 99% of our total estimated net proved reserves as of December 31, 2012, 99% of our average daily net production for the month ended December 31, 2012 and 99% of our standardized measure as of December 31, 2012. The following is a summary of each of our properties within our core areas. All of the following descriptions are based on our December 31, 2012 audited reserve report.

Southern Oklahoma

Highlands Unit. The Highlands Unit is in the SE Joiner City Field, an oil-weighted field located in Love County, Oklahoma. Production from the Highlands Unit is from the Deese formation at an average depth of approximately 8,000 feet. The Highlands Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during October 2008, and production response to injection started in April 2009. We own 32 gross (23 net) producing, 24 gross injection (17 net) and 3 gross (2 net) recently drilled but not completed wells in this unit with an average working interest of 71%. During December 2012, our properties in this unit were producing 947 Boe per day gross, 547 Boe per day net, and contained 3,665 MBoe of estimated net proved reserves. As a result of ongoing response to waterflooding, proved producing and proved developed reserves represent 31% and 42%, respectively, of the total proved reserves for this unit, as of December 31, 2012.

Battle Springs Unit. The Battle Springs Unit is in the SE Joiner City Field, an oil-weighted field located in Love County, Oklahoma. Production from the Battle Springs Unit is from the Deese formation at an average depth of approximately 8,850 feet. The Battle Springs Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during September 2006, and production response to injection started in December 2006. We own 25 gross (13 net) producing, 18 gross injection (9 net), and 1 gross (1 net) recently drilled but not completed wells in this unit with an average working interest of 51%. During December 2012, our properties in this unit were producing 609 Boe per day gross, 248 Boe per day net, and contained 964 MBoe of estimated net proved reserves. As a result of ongoing response to waterflooding, proved producing and proved developed reserves represent 62% and 77%, respectively, of the total proved reserves for this unit, as of December 31, 2012.

Twin Forks Unit. The Twin Forks Unit is in the SE Joiner City Field, an oil-weighted field located in Carter County, Oklahoma. Production from the Twin Forks Unit is from the Deese formation at an average depth of approximately 7,000 feet. The Twin Forks Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during September 2009, and production response to injection started in October 2010. We own 10 gross (7 net) producing, 4 gross (3 net) injection and 1 gross (1 net) recently drilled but not completed wells in this unit with an average working interest of 64%. During December 2012, our properties in this unit were producing 975 Boe per day gross, 503 Boe per day net, and contained 1,157 MBoe of estimated net proved reserves. As a result of ongoing response to waterflooding, proved producing and proved developed reserves represent 51% and 75%, respectively, of the total proved reserves for this unit, as of December 31, 2012.

Ardmore West Unit. The Ardmore West Unit is in the Ardmore West Field, an oil-weighted field located in Carter County, Oklahoma. Production from the Ardmore West Unit is from the Deese formation at an average depth of approximately 7,200 feet. The Ardmore West Unit is a waterflood currently being developed which was formed in July 2010 and is operated by our affiliate, Mid-Con Energy Operating. Injection began during September 2011. We own 4 gross (4 net) producing and 4 gross (4 net) injection and 3 gross (3 net) recently drilled but not completed wells in this unit with an average working interest of 97%. During December 2012, our properties in this unit were producing 34 Boe per day gross, 26 Boe per day net, and contained 744 MBoe of estimated net proved reserves. Proved producing and proved developed reserves represent 10% and 57%, respectively, of the total proved reserves for this unit, as of December 31, 2012.

Southeast Hewitt Unit. The Southeast Hewitt Unit is in the SE Wilson Field, an oil-weighted field located in Carter County, Oklahoma. Production from the Southeast Hewitt Unit is from the Deese formation at an average depth of approximately 6,000 feet. The Southeast Hewitt Unit is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during June 1997, and production response to injection started in November 1997. We own 9 gross (2 net) producing and 6 gross (2 net) injection wells in this unit with an average working interest of 24%. During December 2012, our properties in this unit were producing 192 Boe per day gross, 36 Boe per day net, and contained 111 MBoe of estimated net proved reserves for this unit.

Northeastern Oklahoma

Cleveland Field. The Cleveland Field is an oil-weighted field located in Pawnee County, Oklahoma. Production from the Cleveland Field is primarily from the multiple Pennsylvanian age sands at depths from 1,000 to 2,400 feet. Approximately 1,800 gross acres in the Cleveland Field is being operated by our affiliate, Mid-Con Energy Operating. Approximately 1,000 of the total 1,800 gross acres have been acquired in the last four years. We have been actively developing our Cleveland Field leases through drilling, recompletions and workovers, resulting in a significant increase of net production within the last two years. The majority of Mid-Con Energy Operating operated leases are produced under waterflood. We operate 118 gross (114 net) producing wells and 29 gross (27 net) injection wells in this field with an average working interest of 97%. During December 2012, our properties in this field were producing 320 Boe per day gross, 269 Boe per day net, and contained 2,127 MBoe of estimated net proved reserves. The Cleveland Field is flooded on a lease basis and not as a unit, with the date of production response to injection varying from lease to lease.

Cushing Field. The Cushing Field, one of the largest oil fields (by total historical production volume) in the United States is an oil-weighted field located in Creek County, Oklahoma. Production from the Cushing Field is primarily from multiple Pennsylvanian age sands at depths from 1,200 to 2,500 feet. Our affiliate, Mid-Con Energy Operating, operates approximately 3,360 acres in the Cushing Field, the majority of which are being produced under waterflood. We operate 79 gross (30 net) producing wells and 39 gross (14 net) injection wells in this field with an average working interest of 37%. During December 2012, our properties in this field were producing 346 Boe per day gross, 108 Boe per day net, and contained 689 MBoe of estimated net proved reserves. The Cushing field is flooded on a lease basis and not as units, with waterflood responses varying from lease to lease.

Skiatook Project. The Skiatook Waterflood Project is in the Skiatook Field, an oil-weighted field located in Osage County, Oklahoma. Production from the Skiatook Project is primarily from the Bartlesville and Burgess formations at an average depth of approximately 1,600 feet. The Skiatook Project was developed by and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during December 2006, and production response to injection started in January 2008. We own 13 gross (13 net) producing and 3 gross (3 net) injection wells in this field with a working interest of 100%. During December 2012, our properties in this field were producing 38 Boe per day gross, 31 Boe per day net, and contained 218 MBoe of estimated net proved reserves.

Hugoton Basin

War Party I and II Units. The War Party I and II Units are in the SE Guymon Field, an oil-weighted field located in Texas County, Oklahoma. Production from the War Party I and II Units is from the Cherokee formation at an average depth of approximately 5,800 feet. The War Party I and II Units are operated by our affiliate, Mid-Con Energy Operating, and both are being produced under waterflood. Injection began during November 2001 and July 2002 for War Party Unit I and War Party Unit II, respectively, and production response to injection started in February 2002 and March 2003 for War Party Unit I and War Party Unit II, respectively. We own 32 gross (32 net) producing wells and 14 gross (14 net) injection and 9 gross (9 net) shut-in wells in both units with an average working interest in War Party I of 100% and in War Party II of 99%. During December, 2012, our properties in these units contained 1,275 MBoe of estimated net proved reserves. Production during December 2012 was 254 Boe per day gross, 220 Boe per day net. These are mature waterflood properties which have already reached peak production rates and where injection commenced several years prior to our acquisition.

Harker Ranch Unit. The Harker Ranch Unit is in the Harker Ranch Field, an oil-weighted field located in Cheyenne County, Colorado. Production from the Harker Ranch Field is from the Morrow formation at an average depth of approximately 5,200 feet. The Harker Ranch Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during September 2006, and production response to injection started in May 2008. We own 4 gross (4 net) producing and 2 gross (2 net) injection wells in this unit with a working interest of 100%. During December 2012, our properties in this unit were producing 148 Boe per day gross, 122 Boe per day net, and contained 208 MBoe of estimated net proved reserves.

Clawson Ranch Waterflood Unit. The Clawson Ranch Waterflood Unit is in the North Hitchland Field, an oil-weighted field located in Texas County, Oklahoma. Production from the Clawson Ranch Waterflood Unit is from the Cherokee formation at an average depth of approximately 5,700 feet. The Clawson Ranch Waterflood Unit is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during April 2001, and production response to injection started in April 2002. We own 15 gross (15 net) producing and 7 gross (7 net) injection wells in this unit with a working interest of 100%. As of December 31, 2012, our properties in this unit were producing 256 Boe per day gross, 214 Boe per day net. As of December 31, 2012, the Clawson Ranch Waterflood Unit contained 1,654 MBoe of estimated net proved reserves. Proved producing and proved developed reserves represent 57% and 86%, respectively, of the total proved reserves for this unit as of December 31, 2012.

Other Properties

Decker Unit. The Decker Unit is in the NW Little Field, an oil-weighted field located in Seminole County, Oklahoma. Production from the Decker Unit is from the Earlsboro formation at an average depth of approximately 3,600 feet. The Decker Unit was formed and is operated by our affiliate, Mid-Con Energy Operating, and is being produced under waterflood. Injection began during December 2008, and production response to injection started in September 2009. We own 8 gross (8 net) producing and 4 gross (4 net) injection wells in this unit with an average working interest of 98%. During December 2012, our properties in this unit were producing 24 Boe per day gross, 19 Boe per day net, and contained 210 MBoe of estimated net proved reserves. As a result of ongoing response to waterflooding, proved producing and proved developed reserves represent 30% and 100%, respectively, of the total proved reserves as of December 31, 2012.

The balance of the Company's properties, located throughout the State of Oklahoma, consist of a mix of operated and non-operated properties, none of which are under waterflood. As of December 31, 2012, our other properties contained approximately 124 MBoe of estimated net proved reserves and generated average net production of approximately 33 Boe per day for the month ended December 31, 2012.

Oil and Natural Gas Reserves and Production

Internal Controls Relating to Reserve Estimates

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our reservoir engineering staff. Internal evaluations of our reserves are maintained in a secure reserve engineering database. Reserves are reviewed internally by our senior management on a quarterly basis. Our reserve estimates are audited by our independent third-party reserve engineers, Cawley, Gillespie & Associates, Inc., at least annually.

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

Technology Used to Establish Proved Reserves

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

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

Qualifications of Responsible Technical Persons

Cawley, Gillespie & Associates, Inc. is an independent oil and natural gas consulting firm. No director, officer, or key employee of Cawley, Gillespie & Associates, Inc. has any financial ownership in the Mid-Con Affiliates, Mid-Con Energy Operating, Yorktown or any of their respective affiliates. Cawley, Gillespie & Associates, Inc.’s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. Cawley, Gillespie & Associates, Inc. has performed services for certain of Yorktown’s portfolio companies. The engineering audit presented in the Cawley, Gillespie & Associates, Inc. report was overseen by Bob Ravnaas, P.E., Executive Vice President. Mr. Ravnaas is an experienced reservoir engineer having been a practicing petroleum engineer since 1981. He has more than 29 years of experience in reserves evaluation. Mr. Ravnaas received a BS with special honors in Chemical Engineering from the University of Colorado at Boulder in 1979, and a M.S. in Petroleum Engineering from the University of Texas at Austin in 1981. He is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum Geologists and the Society of Petrophysicists and Well Log Analysts.

Estimated Proved Reserves

The following table presents our estimated net proved oil and natural gas reserves associated with our estimated proved reserves attributable to our properties as of December 31, 2012, based on reserve reports prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc.

	Oil Net MBoe	Gas Net MBoe	Total Net MBoe
Reserve Data: (1)			
Estimated proved developed reserves	8,727	72	8,799
Estimated proved undeveloped reserves	4,347	—	4,347
Total:	13,074	72	13,146

(1) Our estimated net proved reserves were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month price for the prior twelve months were $94.71 per Bbl for oil and $2.752 per MMBtu for natural gas at December 31, 2012. These prices were adjusted by lease for quality, transportation fees, location differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

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

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

Production, Revenue and Price History

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

Development of Proved Undeveloped Reserves

None of our proved undeveloped reserves at December 31, 2012, are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. Consistent with the typical waterflood response time range of six to eighteen months from initial development, the transfer of proved undeveloped reserves to the proved developed category through drilling is attributable to development costs incurred in prior years. During 2012, our capital expenditures for development drilling were approximately $15.7 million. Based on our current expectations of our cash flow, we believe that we can fund the development of our proved undeveloped reserves associated with our waterflood operations from our cash flow from operations and, if needed, borrowings from our new credit facility. For a more detailed discussion of our pro forma liquidity position, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Development Activities

Since January 2012, we have undertaken an extensive program consisting of drilling approximately 39 gross (30 net) development wells, the majority of which reside in our Southern and Northeastern Oklahoma core areas. Approximately 18% of these development wells are injection wells and the remainders are producing wells. The program has continued to successfully increase injection and production and will continue on into 2013.

In our Northeastern Oklahoma core area, since early 2010, we have been engaged in an active acquisition and corresponding exploitation program in our Cleveland Field. We have acquired a number of leases adjacent to our legacy properties that have been operated by Mid-Con Energy Operating. These acquisitions have resulted in an approximate doubling of our acreage position in the field. Our continued exploitation program has consisted of returning wells to production on acquired leases, recompleting shallower horizons, and expanding waterflood operations to include previously unflooded reservoirs.

During June 2012, we acquired significant working interests in our existing assets in our Southern Oklahoma core area. Additionally in October 2012, we acquired additional working interests in our War Party I and II Units which took our working interest to just under 100%. Finally in November 2012, we acquired 100% working interest in the Clawson Ranch Waterflood Unit in our Hugoton Basin core area. In each of these three Hugoton Basin properties, workover and drilling programs have been implemented to return wells to production, optimize the fields' productivity and contact additional reservoir.

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

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Developmental wells:						
Productive	31	23	34	21	21	13
Injection	7	6	12	9	10	5
Water Supply	—	—	—	—	—	—
Dry	1	1	2	1	4	2
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	31	23	34	21	21	13
Injection	7	6	12	9	10	5
Water Supply	—	—	—	—	—	—
Dry	1	1	2	1	4	2
Total:	39	30	48	31	35	20

We are currently conducting multiple development activities, including the drilling of 1 gross (1 net) production well in our Southern Oklahoma core area. Because we focus primarily on secondary recovery, our drilling activity is not indicative of our development activity as is typical with oil and gas exploration and primary production companies. Additionally, we are in the process of completing 5 gross (3 net) recently drilled wells in our Southern Oklahoma core area and 2 gross (1 net) recently drilled wells in our Northeastern Oklahoma core area.

Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2012. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas		Injection		Water Supply Wells		Shut-in / Waiting on Completion		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated	359	271	1	1	155	107	14	11	69	61	598	451
Non-operated	1	—	4	1	—	—	—	—	—	—	5	1
Total	**360**	**271**	**5**	**2**	**155**	**107**	**14**	**11**	**69**	**61**	**603**	**452**

Developed Acreage

The following table sets forth information relating to our leasehold acreage. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table. As of December 31, 2012 substantially all of our leasehold acreage was held by production:

	Developed Acreage	
	Gross	Net
Southern Oklahoma	8,744	5,280
Northeastern Oklahoma	6,319	3,939
Hugoton Basin	9,232	9,203
Other	1,281	763
Total	**25,576**	**19,185**

Delivery Commitments

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

Operations

General

We operate approximately 99% of our properties, as calculated on a Boe basis as of December 31, 2012, through our affiliate, Mid-Con Energy Operating. All of our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies. We design and manage the development, recompletion or workover for all of the wells we operate and supervise operation and maintenance activities. We do not own the drilling rigs or other oil field services equipment used for drilling or maintaining wells on the properties we operate.

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

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

Geological and Engineering Services

Mid-Con Energy Operating employs production and reservoir engineers, geologists and land specialists, as well as field production supervisors. Through the services agreement, we have the direct operational support of a staff of over 25 petroleum professionals with significant technical expertise. We believe that this technical expertise, which includes extensive experience utilizing secondary recovery methods, particularly waterfloods, differentiates us from, and provides us with a competitive advantage over, many of our competitors. Please read "Certain Relationships and Related Party Transactions — Services Agreement."

Administrative Services

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

Oil and Natural Gas Leases

The typical oil lease agreement covering our properties provides for the payment of royalties to the mineral owner for all hydrocarbons produced from any well drilled on the lease premises. The lessor royalties and other leasehold burdens on our properties range from less than 10% to 33%, resulting in a net revenue interest to us ranging from 67% to 87.5%, or 84.1% on average, on a 100% working interest basis. Most of our leases are held by production and do not require lease rental payments.

Principal Customers

For the year ended December 31, 2012, sales of oil and natural gas to Enterprise Crude Oil, LLC ("Enterprise"), Vitol, Inc., and Sunoco Logistics Partners L.P. ("Sunoco") accounted for approximately 32%, 28%, and 21%, respectively, of our sales volumes. No other customer accounted for more than 10% of our total revenues for the year ended December 31, 2012.

We recently entered into a new crude oil purchase contract with Enterprise, which was effective as of January 1, 2013. We anticipate that, as a result of this new contract, sales to Enterprise will account for a significant portion of our 2013 sales revenues. Our production is and will continue to be marketed by our affiliate, Mid-Con Energy Operating, under these crude oil purchase contracts. By selling production to fewer purchasers 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.

The loss of any of our customers could temporarily delay production and sale of our oil and natural gas. If we were to lose any of our significant customers, we believe that under current market conditions, 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 finding substitute customers to purchase our production volumes at comparable rates.

Hedging Activities

We continue to enter into commodity derivative contracts with unaffiliated third parties to achieve more predictable cash flow and to reduce our exposure to short-term fluctuations in oil and natural gas prices. All of our derivative contracts for 2013 and 2014 are either swaps with fixed settlements or collars with NYMEX prices and option agreements. For a more detailed discussion of our hedging activities, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources” and “Item 7A. Quantitative and Qualitative Disclosure About Market Risk.”

Competition

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

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

Title to Properties

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

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

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

Hydraulic Fracturing

Hydraulic fracturing has been a routine part of the completion process for the majority of the wells on our producing properties in Oklahoma and Colorado for several decades. Most of our properties are dependent on our ability to hydraulically fracture the producing formations. We are currently conducting hydraulic fracturing activities in our Northeastern Oklahoma and Southern Oklahoma core areas. All of our leasehold acreage is currently held by production from existing wells. Therefore, fracturing is not currently required to maintain this acreage but it will be required in the future to develop the majority of our proved behind pipe and proved undeveloped reserves associated with this acreage. Nearly all of our proved behind pipe and proved undeveloped reserves associated with future drilling and recompletion projects, or 34% of our total estimated proved reserves as of December 31, 2012 will be subject to hydraulic fracturing. Although the cost of each well will vary, on average approximately 12.5% of the total cost of drilling and completing a well is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into and funded through our normal capital expenditure budget.

Almost all of our hydraulic fracturing operations are conducted on vertical wells. The fracture treatments on these wells are much smaller and utilize much less water than what is typically used on most of the shale gas wells that are being drilled throughout the United States. For example, a “typical” hydraulic fracture stimulation on a Marcellus shale well is pumped in five or more stages, utilizing a total of 4 million gallons of water and 1.5 million pounds of sand. In comparison, for our wells, large hydraulic fracture stimulation on one of our new wells would be pumped in three stages utilizing a total of 50,000 gallons of water and 60,000 pounds of sand. Typical hydraulic fracture stimulation for a recompletion of one of our existing wells would be pumped in one stage, utilizing about 20,000 gallons of water and 15,000 pounds of sand.

We follow applicable industry standard practices and legal requirements for groundwater protection in our operations, subject to close supervision by state and federal regulators, which conduct many inspections during operations that include hydraulic fracturing. These protective measures include setting surface casing below the deepest known depth of all subsurface potable water, a depth sufficient to protect fresh water zones as determined by regulatory agencies, and cementing the well casing to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design essentially eliminates a pathway for underground migration of the fracturing fluid to contact any fresh or potable water aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Chemical additives used in hydraulic fracturing are described in our hydraulic fracturing contractor’s material safety data sheets which describe their proper use and safe handling procedures. Fracturing contractor employees are trained in the safe handling of all fracturing fluids, chemical additives and materials and are required to wear appropriate protective clothing, eye and foot wear. Other protective measures include extensive safety briefings prior to conducting fracturing operations, testing of pumping equipment and surface lines to pressures exceeding expected maximum fracture treating pressures prior to conducting fracturing operations, detailed fracture treating process checklists used by our fracturing contractors, and guidelines for the disposal of excess fracturing fluids.

Fracture treating rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on surface pumping equipment and associated treating lines, the treating string and, where applicable, the immediate annulus to the treating string. Hydraulic fracturing operations would be shut down if an abrupt change occurred in the treating pressure or annular pressure.

Regulations applicable to our operating areas do not currently require, and we do not currently evaluate, the environmental impact of typical additives used in fracturing fluid. We note, however, that approximately 98% of the hydraulic fracturing fluids we use are made up of water and sand.

We minimize the use of water and dispose of it in a way that essentially eliminates the impact to nearby surface water by disposing excess water and water that is produced back from the wells into approved disposal or injection wells. We currently do not intentionally discharge water to the surface.

To our knowledge, there have not been any incidents, citations or suits related to environmental concerns from our fracturing operations.

If a surface spill or a leak were to occur, it would be controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions, as well as any Spill Prevention, Control and Countermeasures ("SPCC") plans we maintain in accordance with EPA requirements. This would include any action up to and including total abandonment of the wellbore.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and cleanup costs stemming from a sudden and accidental pollution event. We may not have coverage if we are unaware of the pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events.

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

We maintain insurance coverage against potential losses that we believe is customary in the industry. We currently maintain general liability insurance and commercial umbrella liability insurance with limits of $1.0 million and $5.0 million per occurrence, respectively, and $2.0 million and $5.0 million in the aggregate, respectively. There is a $1,000 per claim deductible for only our property damage liability and our containment and pollution coverage included as part of our general liability insurance and a $10,000 retention for our commercial umbrella liability insurance. Our general liability insurance covers us for, among other things, legal and contractual liabilities arising out of property damage and bodily injury, for sudden or accidental pollution liability. Our commercial umbrella liability insurance is in addition to, and triggered if, the general liability insurance policy limits are exceeded. In addition, we maintain control of well insurance with per occurrence limits of $5.0 million and retentions of $50,000. Our control of well policy insures us for blowout risks associated with drilling, completing and operating our wells, including above ground pollution.

Our current insurance policies provide coverage for losses arising out of our hydraulic fracturing operations. These policies may not cover fines, penalties or costs and expenses related to government mandated clean-up of pollution. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Environmental Matters and Regulation

General

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

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

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

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

Hazardous Substances and Waste

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

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

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

Water Discharges

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

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

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

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We employ conventional hydraulic fracturing techniques to increase the productivity of certain of our properties. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into rock formations to fracture the surrounding rock and stimulate production. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has published draft guidance documents related to this newly asserted regulatory authority. In addition, Congress has considered federal regulation of hydraulic fracturing including disclosure of the chemicals used in the hydraulic fracturing process. In December 2011, the Colorado Oil and Gas Conservation Commission adopted rules requiring operators to disclose chemical ingredients and concentrations used in hydraulic fracturing treatments beginning on April 1, 2012. On July 1, 2012, the Oklahoma Corporation Commission adopted new 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. Certain proprietary information may be excluded from an operator's disclosure. The new disclosures apply to horizontal wells that are hydraulically fractured on or after January 1, 2013 and to other wells that are hydraulically fractured on or after January 1, 2014. Additionally, some states, and local governments have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. For example, the State of Arkansas established a moratorium on waste water injection in certain areas hydraulic fracturing activities due to concern that such activities may be related to increased earthquake activity. We follow applicable industry standard practices and legal requirements for groundwater protection in our hydraulic fracturing activities. In the event that new or more stringent federal, state or local legal restrictions are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and published an update on December 21, 2012 with final results expected by 2014. The EPA has also announced that it is launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. 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. On April 13, 2012, the Department of Interior, the Department of Energy and the Environmental Protection Agency issued a memorandum outlining a multi-agency collaboration on unconventional oil and gas research in response to the White House "Blueprint for a Secure Energy Future" and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. On September 5, 2012, the U.S. Government Accountability Office issued two reports concerning environmental and health risks and key environmental and public health requirements related to hydraulic fracturing but did not make any recommendations. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

To our knowledge, there have not been any citations, suits or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Air Emissions

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

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

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, or CO_2, methane, and other greenhouse gases, or GHGs, present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. These regulations include requirements to regulate emissions of GHGs from motor vehicles, certain requirements for construction and operating permit reviews for GHG emissions from certain large stationary sources, requiring the reporting of GHG emissions from specified large GHG emission sources including operators of onshore oil and natural gas production and rules requiring so-called green completions of natural gas wells beginning 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 currently exceed the threshold level of GHG emissions triggering a reporting obligation. To the extent we exceed the applicable regulatory threshold level in the future, we will report the emissions beginning in the applicable period. Also, Congress has from time to time considered legislation to reduce emissions of GHGs and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur significant costs to reduce emissions of GHGs associated with operations or could adversely affect demand for our production.

National Environmental Policy Act

Oil exploration, development and production activities on federal lands are subject to the National Environmental Policy Act, as amended, ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that analyses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Currently, we have no exploration and production activities on federal lands. However, for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA may be required. This process has the potential to delay the development of oil projects.

Endangered Species Act

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

OSHA

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

Other Regulation of the Oil and Natural Gas Industry

General

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

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

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

Oil and NGLs Transportation Rates

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

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

Regulation of Oil and Natural Gas Exploration and Production

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

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

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

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

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

Pipeline Safety

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

Employees

The officers of our general partner manage our operations and activities. Neither we, our subsidiary, nor our general partner have employees. Our general partner has entered into a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating will perform services for us, including the operation of our properties. Mid-Con Energy Operating has over 65 employees performing services for our operations and activities. We believe that Mid-Con Energy Operating has a satisfactory relationship with these employees.

Offices

Our headquarters are located at 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201, with approximately 4,000 square feet of office space under lease. Our Dallas lease expires in 2016. For our principal operating office, we currently lease approximately 13,350 square feet of office space in Tulsa, Oklahoma at 2431 East 61st Street, Suite 850, Tulsa, Oklahoma 74136. Our Tulsa lease expires in December, 2016.

Financial Information

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

Available Information

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

ITEM 1A. RISK FACTORS

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

Risks Related to Our Business

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

We may not have sufficient available cash each quarter to pay the quarterly distribution at the current distribution level or any distribution at all, on our units. Under the terms of our partnership agreement, the amount of cash available for distribution 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;
- the amount and timing of settlements on our commodity derivative contracts;
- 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 will depend on the amount of our outstanding indebtedness and the applicable interest rate.

Further, the amount of cash we have available for distribution depends primarily on our cash flow, including cash from financial reserves and borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

A decline in oil prices, or an increase in the differential between the NYMEX or other benchmark prices of oil and the wellhead price we receive for our production, will cause a decline in our cash flow from operations, which could cause us to reduce our distributions or cease paying distributions altogether.

Lower oil prices may decrease our revenues and therefore, our cash available for distribution to our unitholders. Historically, oil prices have been extremely volatile. For example, for the five years ended December 31, 2012, the NYMEX-WTI oil price ranged from a high of $145.29 to a low of $33.87 per barrel. A significant decrease in commodity prices may cause us to reduce the distributions we pay to our unitholders or to cease paying distributions altogether.

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 that are used for calculating hedge positions, such as NYMEX. These discounts, if significant, could similarly reduce our cash available for distribution to our unitholders and adversely affect our financial condition.

If commodity prices decline and remain depressed for a prolonged period, production from a significant portion of our oil properties may become uneconomic and cause write downs of the value of such oil properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Significantly lower oil prices may render many of our development projects uneconomic and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base and ability to borrow to fund our operations or make distributions to our unitholders. As a result, we may reduce the amount of distributions paid to our unitholders or cease paying distributions. In addition, a significant or sustained decline in oil prices could hinder our ability to effectively execute our hedging strategy. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil properties. In addition, if our estimates of drilling 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 properties as impairments. We may incur impairment charges 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 removing the impact of commodity price volatility from our cash flow, which could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

We generally intend to hedge a significant 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 prices at the time we enter into these transactions, which may be substantially higher or lower than current oil prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil prices received for our future production.

Our credit facility may hinder our ability to effectively execute our hedging strategy. To the extent our credit facility limits the maximum percentage of our production that we can hedge or the duration of those hedges, we may be unable to enter into additional commodity derivative contracts during favorable market conditions and, thus, unable to lock in attractive future prices for our product sales. Conversely, while our credit facility will not require us to hedge a minimum percentage of our production, it may cause us to enter into commodity derivative contracts at inopportune times. For example, during a period of declining commodity prices, we may enter into commodity derivative contracts at relatively unattractive prices in order to mitigate a potential decrease in our borrowing base upon a redetermination.

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

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

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to a sudden decrease in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

Unless we replace the oil reserves we produce, our revenues and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders at the initial quarterly distribution rate.

We may be unable to sustain our current quarterly distribution rate of $0.495 per unit without substantial capital expenditures that maintain our asset base. Producing oil reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil reserves and production and, therefore, our cash flow and ability to make distributions are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations and reduce cash available for distribution to our unitholders.

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

We may be required to make substantial capital expenditures from time to time in connection with the production of our oil reserves. Further, if the borrowing base under our credit facility or our revenues decrease as a result of lower oil prices, declines in estimated reserves or production or for any other reason, we may not be able to obtain the capital necessary to sustain our operations at the expected levels so as to generate an amount of cash necessary to make distributions to our unitholders.

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

The cost of developing and operating oil 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 our properties are productive but do not produce as much oil 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;
- unitization difficulties;
- pipe or cement failures, casing collapses or other downhole failures;
- lost or damaged oilfield service tools;
- unusual or unexpected geological formations and reservoir pressure;
- loss of injection fluid circulation;
- 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 well fluids.

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

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

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

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

It is not possible to measure underground accumulations of oil in an exact way. Oil reserve engineering is complex, requiring subjective estimates of underground accumulations of oil and assumptions concerning future oil prices, future production levels and operating and development costs. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could affect our business, results of operations and financial condition and our ability to make distributions to our unitholders.

As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove inaccurate.

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

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

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

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

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

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

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

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

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

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

Also, our reviews of properties acquired from third parties (as opposed to the Mid-Con Affiliates) may be incomplete because it generally is not feasible to perform an in-depth review of such properties, given the time constraints imposed by most sellers. Even a detailed review of the records associated with properties owned by third parties 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 operating areas would reduce our ability to make distributions to our unitholders.

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

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

Sales of oil and natural gas to Enterprise, Vitol Inc., and Sunoco accounted for approximately 31%, 28%, and 20%, respectively of our sales. We entered into a new crude oil purchase contract with Enterprise, which was effective as of January 1, 2013. We anticipate that, as a result of this new contract, Enterprise will account for a significant portion of our 2013 sales revenue. Our production is and will continue to be marketed by our affiliate, Mid-Con Energy Operating, under these crude oil purchase contracts. By selling a substantial majority of our current production to 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. If any of our significant customers reduce the volume of oil they purchase from us, we could experience a temporary interruption in sales of, or may receive a lower price for, our oil production, and our revenues and cash available for distribution could decline which could adversely affect our ability to make cash distributions to our unitholders at the then-current distribution rate or at all.

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

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

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

Other owners of mineral rights may object to our waterfloods.

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

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

The oil and natural gas industry is intensely competitive, and we compete with companies that possess and employ financial, technical and personnel resources substantially greater than ours. 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. 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. 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 during periods of low oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations and our ability to make distributions to our unitholders.

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

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests 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 exploit and develop our reserves.

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

We may be unable to pay distributions at our current distribution rate without borrowing under our credit facility. If we use borrowings under our credit facility to pay distributions to our unitholders for an extended period of time rather than to fund capital expenditures and other activities relating to our operations, we may be unable to maintain or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on our future indebtedness to pay these distributions, will reduce our cash available for distribution on our units and will have a material adverse effect on our business, financial condition and results of operations. If we borrow to pay distributions to our unitholders during periods of low commodity prices and commodity prices remain low, we may have to reduce our distribution to our unitholders to avoid excessive leverage.

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

Our credit facility restricts, among other things, our ability to incur debt and pay distributions under certain circumstances, and requires us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our 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 will be prohibited from making distributions to our unitholders, 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 credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility, the lenders could seek to foreclose on our assets.

The total amount we are able to borrow under our 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. Our lenders increased the borrowing base from $100 million to $130 million in November 2012. Any substantial or sustained decline in commodity prices would likely lead to a decrease in our borrowing base upon redetermination, and in such case, we could be required to repay any indebtedness in excess of the borrowing base. In the future, we may be unable to access sufficient capital under our credit facility as a result of a decrease in our borrowing base due to a subsequent borrowing base redetermination.

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 Environmental Protection Agency, or the EPA, published its findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present a danger to public health and the environment. Based on these findings, the EPA began adopting and implementing regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including requirements to reduce emissions of GHGs 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 beginning in 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, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur significant costs to reduce emissions of GHGs associated with operations or could adversely affect demand for our production.

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

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

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

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the Commodities Futures Trading Commission (the "CFTC"), the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Act the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court (the "District Court") for the District of Columbia in September of 2012, although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap", "security-based swap", "swap dealer" and "major swap participant". The Act and CFTC rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements, although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Act and CFTC rules on us and the timing of such effects. The Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Act and regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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 recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act and has published draft guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In December 2011, the Colorado Oil and Gas Conservation Commission adopted rules requiring operators to disclose chemical ingredients and concentrations used in hydraulic fracturing treatments beginning on April 1, 2012. On July 1, 2012, the Oklahoma Corporation Commission adopted new 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. Certain proprietary information may be excluded from an operator’s disclosure. The new disclosures apply to horizontal wells that are hydraulically fractured on or after January 1, 2013 and to other wells that are hydraulically fractured on or after January 1, 2014. 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 commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, and published an updated on December 21, 2012 with final results expected by 2014. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. On April 13, 2012, the Department of Interior, the Department of Energy and the Environmental Protection Agency issued a memorandum outlining a multi-agency collaboration on unconventional oil and gas research in response to the White House “Blueprint for a Secure Energy Future” and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. On September 5, 2012, the U.S. Government Accountability Office issued two reports concerning environmental and health risks and key environmental and public health requirements related to hydraulic fracturing but did not make any recommendations. 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.

Risks Inherent in an Investment in Us

Our general partner controls us, and the Founders and Yorktown own an approximate 32.3% interest in us. They have conflicts of interest with, and owe limited fiduciary duties to, us, which may permit them to favor their own interests to the detriment of us and our unitholders.

Our general partner has control over all decisions related to our operations. Our general partner is owned by the Founders. As of December 31, 2012, the Founders and Yorktown own an approximate 32.3% interest in us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners. All of the executive officers and non-independent directors of our general partner are also officers and/or directors of the Mid-Con Affiliates and will continue to have economic interests in, as well as management and fiduciary duties to, the Mid-Con Affiliates. 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 Affiliates 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 common unitholders. These potential conflicts include, among others:

- Our partnership agreement limits our general partners' liability, reduces its fiduciary duties and also restricts the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are consenting to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- Neither our partnership agreement nor any other agreement requires the Mid-Con Affiliates 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 Affiliates and Yorktown and their respective affiliates (other than our general partner) have a fiduciary duty to make these decisions in the best interests of their respective equity holders, which may be contrary to our interests;
- The Mid-Con Affiliates and Yorktown and their affiliates are not limited in their ability to compete with us, including with respect to future acquisition opportunities, and are under no obligation to offer or sell assets to us;
- All of the executive officers of our general partner who provide services to us also devote a significant amount of time to the Mid-Con Affiliates and are compensated for those services rendered;
- Our general partner determines the amount and timing of our development operations and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership interests, other investments, including investment capital expenditures in other businesses with which our general partner is or may become affiliated, and cash reserves, each of which can affect the amount of cash that is distributed to unitholders;
- We entered into a services agreement with Mid-Con Energy Operating pursuant to which Mid-Con Energy Operating provides management, administrative and operational services to us, and Mid-Con Energy Operating will also provide these services to the Mid-Con Affiliates;
- 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 Affiliates, 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 Affiliates 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 Affiliates or other affiliates of our general partner. There is no requirement that Mid-Con Energy Operating favor us over these other entities in providing its services. If the employees of Mid-Con Energy Operating do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced.

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

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

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

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

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

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

- a citizen of the United States;

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

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

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by the Founders, as a result of their ownership 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.

Currently, it would be difficult for the public unitholders to remove our general partner without its consent because affiliates of our general partner and Yorktown own sufficient units to make it difficult to remove our general partner. The vote of the holders of at least 66 2/3% of all outstanding units is required to remove our general partner. As of December 31, 2012, the Founders and Yorktown owned approximately 32.3% of our outstanding limited partner units, which will enable those holders, collectively, to make it difficult to remove our general partner.

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

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

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

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

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

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

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

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

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

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

As of December 31, 2012, the Founders and Yorktown own 6,126,660 common units or approximately 32.3% of our limited partner interests. Sales of these units or of other substantial amounts of our common units in the public market, or the perception that these sales may occur, could cause the market price of our common units to decline. Sales of such units could also impair our ability to raise capital through the sale of additional common units.

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

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

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Our unitholders may have liability to repay distributions.

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

Our unitholders may have limited liquidity for their common units, a trading market may not continue to exist for the common units and our unitholders may not be able to resell their common units at their initial purchase price.

Our common units are timely traded on the public market. Our unitholders may not be able to resell their common units at or above their initial purchase price. Additionally, a lack of liquidity would likely result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

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

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

- general economic and market conditions, including interest rates prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and gas industry;
- the market price of, and demand for, our common units;
- our results of operations and financial condition; and
- prices for oil and natural gas.

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

Tax Risks to Unitholders

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

The anticipated after-tax economic benefit of an investment in the units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based on our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions, 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 flow 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 are 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 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, the Obama Administration and members of the U.S. Congress have considered substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Although we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted, any such changes could negatively impact the value of an investment in our units.

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

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

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.

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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 our counsel's conclusions or the positions we take. A court may not agree with some or all our counsel's conclusions or of the positions we take. 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.

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

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

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

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

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

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

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

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and although the United States Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change our method of allocating items of income, gain, loss and deduction among our unitholders.

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

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

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

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

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 Oklahoma and Colorado, each of which currently imposes a personal income tax on individuals. These states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. We may own property or conduct business in other states or foreign countries in the future. It is a unitholder's responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. No amounts have been accrued at December 31, 2012.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common units are traded on the NASDAQ Global Select Market under the symbol "MCEP". Our common units began trading on December 15, 2011, at an Initial Public Offering ("Initial Public Offering") price of $18.00 per common unit. At the close of business on March 6, 2013, based upon information received from our transfer agent and brokers and nominees, we had 72 common unitholders of record. This number does not include owners for whom common units may be held in "street" names. The daily high and low sales prices per common unit for the period from January 1, 2012 through December 31, 2012 were $25.18 and $17.40, respectively. The following table sets forth the range of the daily high and low sale prices per common unit and cash distributions to common unitholders for 2011 and 2012.

	Price Range		Cash Distribution
	High	Low	per Common Unit (1)
2011:			
Fourth Quarter	$18.87	$17.25	$0.057(1)
2012:			
First Quarter	$25.18	$18.25	$0.475
Second Quarter	24.66	17.87	0.475
Third Quarter	24.12	20.31	0.485
Fourth Quarter	23.00	17.40	0.495(2)

(1) The distribution represented a proration of initial quarterly distributions of $0.475 per unit.
(2) On January 23, 2013, the board of directors of our general partner declared a quarterly cash distribution for the fourth quarter 2012 of $0.495 per common unit. The distribution was paid on February 14, 2013.

Cash Distributions to Unitholders

We intend to continue to make cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our credit agreement prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution.

Cash Distribution Policy

Our partnership agreement requires that, within 45 days after the end of each quarter we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. We will distribute approximately 98.1% of our available cash to our common unitholders, pro rata, and approximately 1.9% to our general partner. Our general partner is not entitled to any incentive distributions, and we do not have any subordinated units.

Definition of Available Cash

Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter to:
- provide for the proper conduct of our business (including reserves for future capital expenditures, working capital and operating expenses) subsequent to that quarter;

- comply with applicable law, any of our loan agreements, security agreements, mortgages debt instruments or other agreements; or
- provide funds for distributions to our unitholders (including our general partner) for any one or more of the next four quarters;
- *plus*, if our general partner so determines, all or a portion of cash or cash equivalents on hand on the date of determination of available cash for the quarter.

Use of Securities Act Registration Proceeds

On October 22, 2012, we and Yorktown completed a public offering of an aggregate of 4,600,000 common units representing limited partner interests in us at a price of $21.20 per common unit pursuant to an S-1 Registration Statement (File No. 333-184120) declared effective by the Securities and Exchange Commission on October 17, 2012. 1,000,000 common units were sold by us, and 3,600,000 common units were sold by Yorktown.

We used the net proceeds of approximately $20.4 million from our 1,000,000 common units offering, after deducting underwriting discounts but before offering expenses, to repay borrowings outstanding under our credit facility. We did not receive any proceeds from the 3,600,000 common units sold by Yorktown.

Securities Authorized for Issuance under Equity Compensation Plans

See “Item 11. Executive Compensation—Compensation Discussion and Analysis—Long-Term Incentive Program” for information regarding our equity compensation plans as of December 31, 2012.

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial data of us and our predecessor for the periods and as of the dates indicated. The selected financial data for the years ended December 31, 2012, 2011, 2010 and six months ended December 31, 2009, are derived from our audited financial statements. The selected financial data for the years ended June 30, 2009 and 2008 is derived from the audited financial statements of our predecessor. The selected financial data should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8. Financial Statements and Supplementary Data,” both contained herein.

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

	Mid-Con Energy Partners, LP				Mid-Con Energy Corporation	
	Year Ended December 31,			Six Months Ended December 31,	Year Ended June 30,	
	2012	2011	2010	2009	2009	2008
Revenues:						
Oil sales	$ 60,887	$36,813	$16,853	$ 5,729	$10,246	$13,667
Natural gas sales	674	1,218	1,418	743	2,172	618
Realized gain (loss) on derivatives, net	3,710	(2,157)	(90)	(350)	(669)	(804)
Unrealized gain (loss) on derivatives, net	2,004	3,437	(707)	(147)	1,679	(2,035)
Total revenues	$ 67,275	$39,311	$17,474	$ 5,975	$13,428	$11,446
Operating costs and expenses:						
Lease operating expenses	10,948	8,491	6,237	2,431	5,369	5,005
Oil and gas production taxes	1,965	1,869	822	269	631	946
Impairment of proved oil and gas properties	1,296	—	1,886	9,208	—	—
Dry holes and abandonments of unproved properties	—	813	1,418	—	—	—
Geological and geophysical	—	172	394	—	507	1,296
Depreciation, depletion and amortization	10,324	7,160	5,851	2,552	2,293	1,599
Accretion of discount on asset retirement obligations	126	78	127	58	78	56
General and administrative	11,000	3,595	982	704	1,767	1,871
Total operating costs and expenses	$ 35,659	$22,178	$17,717	$15,222	$10,645	$10,773
Income (loss) from operations	$ 31,616	$17,133	$ (243)	$ (9,247)	$ 2,783	$ 673
Other income (expense):						
Interest income and other	10	216	218	35	119	115
Interest expense	(1,764)	(578)	(98)	(2)	(93)	(3)
Gain on sale of assets	—	1,621	354	—	—	—
Other revenue and expenses, net	—	576	847	118	298	108
Income tax expense—current	—	—	—	—	(625)	—
Income tax benefit (expense) deferred	—	—	—	—	502	(261)
Net income (loss)	$ 29,862	$18,968	$ 1,078	$ (9,096)	$ 2,984	$ 632
Computation of net income (loss) per limited partner unit:						
General partners' interest in net income (loss)	$ 584	$ 379	$ 22	$ (182)		
Limited partners' interest in net income (loss)	$ 29,278	$18,589	$ 1,056	$ (8,914)		
Net income (loss) per limited partner unit (basic and diluted)	$ 1.62	$ 1.05	$ 0.06	$ (0.51)		
Weighted average limited partner units outstanding: (basic and diluted)	18,049	17,640	17,640	17,640		
Balance Sheet Data:						
Working capital	$ 6,254	$ 2,361	$ (1,256)	$ 2,420		
Total assets	158,590	96,611	56,867	40,496		
Long-term debt	78,000	45,000	5,513	337		
Total equity	72,181	43,349	43,072	36,779		
Other Financial Data:						
Adjusted EBITDA	$ 47,681	$23,994	$10,593	$ 2,836		

Non-GAAP Financial Measures

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

- Plus:
  - income tax expense (benefit), if any;
  - interest expense;
  - depreciation, depletion and amortization;
  - accretion of discount on asset retirement obligations ;
  - unrealized losses on commodity derivative contracts;
  - impairment expenses;
  - dry hole costs and abandonments of unproved properties;
  - equity-based compensation; and
  - loss on sale of assets;
- Less:
  - interest income;
  - unrealized gains on commodity derivative contracts; and
  - gain on sale of assets.

Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. We believe Adjusted EBITDA is useful to investors because it is used by our management, by external users of financial statements, such as industry analysts, investors, lenders, rating agencies and others, to assess the cash flow generated by our assets, without regard to financing methods, capital structure or historical cost basis and our ability to incur and service debt and fund capital expenditures. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. Furthermore, Adjusted EBITDA should not be viewed as indicative of the actual amount of cash that is available for distributions or that is planned to be distributed for a given period nor do they equate to available cash as defined in our partnership agreement.

The following table presents our reconciliation of Adjusted EBITDA to Net Income, for each of the periods indicated. The table below further presents a reconciliation of Adjusted EBITDA to cash flow from operating activities, our most directly comparable GAAP financial measure, for each of the periods indicated.

	Mid-Con Energy Partners, LP				Mid-Con Energy Corporation	
	Year Ended December 31,			Six Months Ended December 31,	Year Ended June 30,	
	2012	2011	2010	2009	2009	2008
	(in thousands)				(in thousands)	
Net income (loss)	$29,862	$18,968	$ 1,078	$(9,096)	$ 2,984	$ 632
Income tax (benefit) expense - deferred	—	—	—	—	(502)	261
Income tax expense - current	—	—	—	—	625	—
Interest expense	1,764	578	98	2	93	3
Depreciation, depletion and amortization	10,324	7,160	5,851	2,552	2,293	1,599
Accretion of discount on asset retirement obligations	126	78	127	58	78	56
Unrealized (gain) loss on derivatives, net	(2,004)	(3,437)	707	147	(1,679)	2,035
Impairment of oil and gas properties	1,296	—	1,886	9,208	—	—
Dry hole costs	—	813	1,418	—	—	—
Gain on sales of assets	—	(1,621)	(354)	—	—	—
Equity-based compensation	6,323	1,671	—	—	—	—
Interest income	(10)	(216)	(218)	(35)	(119)	(115)
Adjusted EBITDA	$47,681	$23,994	$10,593	$ 2,836	$ 3,773	$4,471

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

	Mid-Con Energy Partners, LP				Mid-Con Energy Corporation	
	Year Ended December 31,			Six Months Ended December 31,	Year Ended June 30,	
	2012	2011	2010	2009	2009	2008
	(in thousands)				(in thousands)	
Net cash provided by operating activities	$47,717	$24,113	$11,798	$ 965	$10,935	$4,221
Amortization of debt placement fees	(131)	—	—	—	—	—
Change in working capital	(1,659)	(481)	(1,085)	1,904	(7,761)	521
Income tax expense - current	—	—	—	—	625	—
Bad debt expense	—	—	—	—	—	(159)
Interest expense	1,764	578	98	2	93	3
Interest income	(10)	(216)	(218)	(35)	(119)	(115)
Adjusted EBITDA	$47,681	$23,994	$10,593	$2,836	$ 3,773	$4,471

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

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

Overview

We are a Delaware limited partnership formed in July 2011 to own, operate, acquire, exploit and develop producing oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. Our general partner is Mid-Con Energy GP, LLC, a Delaware limited liability company. Our properties are located in the Mid-Continent region of the United States in three core areas: Southern Oklahoma, Northeastern Oklahoma and parts of Oklahoma and Colorado within the Hugoton Basin. Our properties primarily consist of mature, legacy onshore oil reservoirs with long-lived, relatively predictable production profiles and low production decline rates.

We completed our Initial Public Offering in December 2011 and our common units are traded on the NASDAQ Global Select Market under the symbol "MCEP."

As of December 31, 2012, our total estimated proved reserves were approximately 13.1 MMBoe, of which approximately 99% were oil and 67% were proved developed, both on a Boe basis. As of December 31, 2012, we operated 99% of our properties through our affiliate, Mid-Con Energy Operating, and 99% were being produced under waterflood, in each instance on a Boe basis. Our average net production for the month ended December 31, 2012 was approximately 2,376 Boe per day and our total estimated proved reserves had an average reserve-to-production ratio of approximately 15 years.

We are an "emerging growth company" as defined in Section 101 of the Jumpstart Our Business Startups Act of 2012, or the JOBS Act.

Developments in 2012

Acquisitions

During June 2012, we acquired properties in the Northeastern Oklahoma area and additional working interests in our existing units in the Southern Oklahoma area for approximately $16.4 million in separate transactions, subject to customary purchase price adjustments. In addition, we had miscellaneous acquisitions of $0.2 million.

During October 2012, we acquired additional working interests in our War Party Unit I and War Party Unit II located in the Hugoton Basin core area for approximately $3.7 million.

During November 2012, we acquired 100% working interest in the Clawson Ranch Waterflood Unit in our Hugoton Basin core area for approximately $28.9 million, subject to customary purchase price adjustments.

Public Offering of Additional Units

On October 22, 2012, we and Yorktown sold an aggregate of 4,600,000 common units to the public at a price of $21.20 per common unit. 1,000,000 common units were sold by us, and 3,600,000 common units were sold by Yorktown. We used the net proceeds of approximately $20.4 million from the sale of our 1,000,000 common units, after deducting underwriting discounts but before offering expenses, to repay borrowings outstanding under our credit facility. We did not receive any proceeds from the 3,600,000 common units sold by Yorktown.

Other

During April 2012, the borrowing base under our credit facility was increased from $75.0 million to $100.0 million and Wells Fargo Bank, N.A. was added as an additional lender. No other material terms of the original credit agreement were amended.

During November 2012, the borrowing base under our credit facility was increased from $100.0 million to $130.0 million and Comerica Bank was added as an additional lender. No other material terms of the original credit agreement were amended.

Business Environment

The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future, which means that the price of oil can fluctuate widely. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil reserves that we can economically produce and our access to capital.

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program's objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distributions over time, while retaining some ability to participate in upward moves in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher amount of hedges in the near 12 months.

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

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

How We Evaluate Our Operations

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

- the amount of oil and natural gas we produce;
- the prices at which we sell our oil and natural gas production;
- our ability to hedge commodity prices; and
- the level of our operating and administrative costs.

We use a variety of financial and operational metrics to assess the performance of our oil properties, including:

- Oil and natural gas production volumes;
- Realized prices on the sale of oil and natural gas, including the effect of our commodity derivative contracts;
- Lease operating expenses; and
- Adjusted EBITDA.

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

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

In addition, management uses Adjusted EBITDA to evaluate actual potential cash flow available to pay distributions to our unitholders, develop existing reserves or acquire additional oil properties.

Critical Accounting Policies and Estimates

Oil and Natural Gas Quantities

Our estimates of proved reserves are based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The estimates of our proved reserves as of December 31, 2012 are based on reserve reports prepared by our reservoir engineering staff and audited by Cawley, Gillespie & Associates, Inc. The accuracy of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions, and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are also a function of many assumptions, all of which could deviate significantly from actual results. For example, when the price of oil and natural gas increases, the economic life of our properties is extended, thus increasing estimated proved reserve quantities and making certain projects economically viable. Likewise, if oil and natural gas prices decrease, the properties economic life is reduced and certain projects may become uneconomic, reducing estimated proved reserved quantities. Oil and natural gas price volatility adds to the uncertainty of our reserve quantity estimates. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas and NGLs.

Successful Efforts Method of Accounting

We account for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

We evaluate the impairment of our proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flow is less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flow to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and developmental costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flow is the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation and depletion unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Impairment of Oil and Natural Gas Properties

We review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and risk-adjusted probable and possible oil and gas reserves over the economic life of the reserves based on our expectations of future oil and gas prices and costs. We review our oil and gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base.

Asset Retirement Obligations

The initial estimated asset retirement obligation ("ARO") associated with oil and natural gas properties is recognized as a liability, with a corresponding increase in the carrying value of oil and natural gas properties. Amortization expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated ARO changes, an adjustment is recorded to both the liability and the carrying value of the property. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling AROs.

Revenue Recognition

Oil and natural gas revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Virtually all of our contracts' pricing provisions are tied to a market index with certain adjustments based on, among other factors, the quality of oil, location differentials and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

Derivative Contracts and Hedging Activities

Current accounting rules require that all derivative contracts, other than those that meet specific exclusions, be recorded at fair value. Quoted market prices are the best evidence of fair value. If quotations are not available, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or on other valuation techniques.

Our derivative contracts are traded transactions on an exchange, so valuation is determined by reference to readily available public data.

We recognize all of our derivative contracts as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative contract depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative contracts that are designated and qualify as hedging instruments, we designated the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative contracts not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of our derivatives were designated as a hedging instrument during the twelve months ended December 31, 2012, 2011 and 2010.

Results of Operations

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated (in thousands).

	Mid-Con Energy Partners, LP		
	Year Ended December 31,		
	2012	2011	2010
Revenues:			
Oil sales	$60,887	$36,813	$16,853
Natural gas sales	674	1,218	1,418
Realized gain (loss) on derivatives, net	3,710	(2,157)	(90)
Unrealized gain (loss) on derivatives, net	2,004	3,437	(707)
Total revenues	$67,275	$39,311	$17,474
Operating costs and expenses:			
Lease operating expenses	$10,948	$ 8,491	$ 6,237
Oil and gas production taxes	1,965	1,869	822
Impairment of proved oil and gas properties	1,296	—	1,886
Dry holes and abandonments of unproved properties	—	813	1,418
Depreciation, depletion and amortization (1)	10,324	6,795	5,204
General and administrative (2)	11,000	3,767	1,376
Interest expense	(1,764)	(578)	(98)
Gain on sale of assets	—	1,621	354
Production:			
Oil (MBbls)	678	407	228
Natural gas (MMcf)	122	164	191
Total (MBoe)	698	434	260
Average net production (Boe/d)	1,907	1,191	710
Average sales price:			
Oil (per Bbl):			
Sales price	$ 89.80	$ 90.45	$ 73.92
Effect of realized commodity derivative instruments	$ 5.47	$ (5.30)	$ (0.39)
Realized price	$ 95.27	$ 85.15	$ 73.53
Natural gas (per Mcf):			
Sales price (3)	$ 5.52	$ 7.43	$ 7.42
Average unit costs per Boe:			
Lease operating expenses	$ 15.68	$ 19.56	$ 23.99
Oil and gas production taxes	$ 2.82	$ 4.31	$ 3.16
General and administrative expenses	$ 15.76	$ 8.67	$ 5.29
Depreciation, depletion and amortization	$ 14.79	$ 15.66	$ 20.02

(1) Depreciation, depletion and amortization expenses for this table only represents the depletion expense for the producing properties.

(2) General and administrative expenses include non-cash, equity-based compensation of $6.3 million and $1.7 million for the years ended December 31, 2012 and 2011, respectively.

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

Factors Affecting the Comparability of the Historical Financial Results

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

- The drilling of 35 wells in 2010, 48 wells in 2011, and 39 wells in 2012 on our properties;
- The acquisition of interests in various properties located in Oklahoma for an aggregate purchase price of approximately $6.5 million throughout the year in 2010;
- Our sale to the Mid-Con Affiliates on June 30, 2011 of certain properties representing less than 1% of our proved reserves by value, as calculated using the standardized measure, as of September 30, 2011, and certain subsidiaries that do not own oil and natural gas reserves, including Mid-Con Energy Operating, to the Mid-Con Affiliates for aggregate consideration of $7.5 million;
- Our acquisition of the War Party I and II Units for a purchase price of $7.2 million in June 2011;
- Our acquisition in December 2011 of additional working interest in the Cushing Field for $6.0 million;
- Our acquisition in June 2012 of properties in Northeastern Oklahoma and additional working interests in Southern Oklahoma for $16.4 million, subject to customary purchase price adjustments;
- Our acquisition in October 2012 of additional working interests in the War Party I and II Units for $3.7 million; and
- Our acquisition in November 2012 of the Clawson Ranch Waterflood Unit for $28.9 million, subject to customary purchase price adjustments.

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

Year Ended December 31, 2012 Compared with Year Ended December 31, 2011.

Net income was approximately $29.9 million for the year ended December 31, 2012 compared to approximately $19.0 million for the year ended December 31, 2011, an increase of approximately $10.9 million. This increase was primarily attributable to an increase in oil sales and the favorable net effect of our derivatives, partially offset by higher general and administrative expenses (including equity-based compensation expense), higher depreciation, and lease operating expenses, as a result of our continued growth.

Sales Revenues. Revenues from oil and natural gas sales for the year ended December 31, 2012 were approximately $61.6 million as compared to approximately $38.0 million for the year ended December 31, 2011. The increase in revenues was primarily due to an increase in daily oil production which includes incremental volumes from recent acquisitions.

On average, our production volumes for the year ended December 31, 2012 were approximately 698 MBoe, or approximately 1,907 Boe per day. In comparison, our total production volumes for the year ended December 31, 2011 were approximately 434 MBoe, or approximately 1,191 Boe per day on average. The increase in production volumes was primarily due to ongoing waterflood response to injection as well as from wells drilled as part of drilling program in our Southern Oklahoma core area. Furthermore, the increase in production for the year ended December 31, 2012 reflects the impact from various acquisitions of oil properties and additional working interest during 2012. Our average sales price per barrel of oil, excluding commodity derivative contracts, for the year ended December 31, 2012 was $89.80, compared with $90.45 for the year ended December 31, 2011.

Effects of Commodity Derivative Contracts. We utilize NYMEX contracts to hedge against changes in commodity prices. Due to the period change in the mark-to-market value of these contracts, we recorded a net gain from our commodity hedging program for the year ended December 31, 2012 of approximately $5.7 million, which was composed of a realized gain of approximately $3.7 million and an unrealized gain of approximately

$2.0 million. For the year ended December 31, 2011, we recorded a net gain from our commodity hedging program of approximately $1.3 million, which was composed of an unrealized gain of $3.4 million and a realized loss of approximately $2.1 million.

Lease Operating Expenses. Our lease operating expenses were approximately $10.9 million for the year ended December 31, 2012, or $15.68 per Boe, compared to approximately $8.5 million for the year ended December 31, 2011, or approximately $19.56 per Boe. The increase in total lease operating expenses for the year ended December 31, 2012 was primarily attributable to the additional number of producing wells due to our drilling program and the additional oil properties and working interest acquired during 2012. The decrease in lease operating expenses per Boe was due to the increased production for the year ended December 31, 2012. Ad valorem taxes are also reflected in lease operating expenses. Ad valorem taxes are levied on our properties in Colorado and are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts, and a percentage of production equipment value.

Production Taxes. Our production taxes were approximately $2.0 million for the year ended December 31, 2012, or approximately $2.82 per Boe for an effective tax rate of approximately 3.2%, compared to approximately $1.9 million for the year ended December 31, 2011, or approximately $4.31 per Boe for an effective tax rate of approximately 4.9%. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. The State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%. The decrease in price per Boe is due to some of our Southern Oklahoma properties receiving a reduced production tax rate from Oklahoma's Enhanced Recovery Project Gross Production Tax Exemption which has been extended to July 2014.

Impairment Expense. Our impairment expense was approximately $1.3 million for the year ended December 31, 2012. 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 of those assets may not be recoverable. If the carrying amount exceeds the property's estimated fair value, we adjust the carrying amount of the property to fair value through a charge to impairment expense. We recorded a $1.1 million and $0.2 million non-cash impairment charge within our miscellaneous core area gas wells and our Southern Oklahoma core area, respectively. There was no impairment charge for the year ended December 31, 2011.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the year ended December 31, 2012 were approximately $10.3 million, or approximately $14.79 per Boe produced, compared to approximately $6.8 million, or approximately $15.66 per Boe produced, for the year ended December 31, 2011. The increase in depreciation, depletion and amortization expenses was primarily due to the increase in total asset value of the oil and gas properties from our drilling program, the acquisitions of properties in our Hugoton Basin, Southern and Northeastern Oklahoma core areas, and the purchase of additional working interest in our Southern Oklahoma properties. The decrease per Boe produced was primarily due to the increase in total proved and proved developed reserves in 2012.

General and Administrative Expenses. Our general and administrative expenses were approximately $11.0 million for the year ended December 31, 2012, or approximately $15.76 per Boe produced compared to approximately $3.8 million for the year ended December 31, 2011 or approximately $8.67 per Boe produced. The increase in general and administrative expenses for the year ended December 31, 2012 is primarily due to higher compensation costs of $6.5 million related to our equity-based compensation expense, higher professional fees necessary to comply with public reporting requirements, and incremental costs related to the hiring of additional staff. Compensation costs include non-cash equity-based compensation of $6.3 million and its cash based payroll tax costs of $0.2 million.

Interest Expense. Our interest expense for the year ended December 31, 2012 was approximately $1.8 million, compared to approximately $0.6 million for the year ended December 31, 2011. The increase was primarily due to increased borrowings from our credit facility.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010.

Net income was $19.0 million for the year ended December 31, 2011 compared to $1.1 million for the year ended December 31, 2010, an increase of $17.9 million. This increase primarily reflects higher revenues due to increased prices of oil and natural gas partially offset by higher depreciation, depletion and amortization expense along with increased general and administrative expenses and higher operating expenses, as a result of our continued growth.

Sales Revenues. Revenues from oil and natural gas sales for the twelve months ended December 31, 2011 were approximately $38.0 million as compared to $18.3 million for the twelve months ended December 31, 2010. The increase in revenues was primarily due to an increase in daily oil production and higher sales prices during the twelve months ended December 31, 2011.

Our production volumes for the twelve months ended December 31, 2011 were 434 MBoe, or 1,191 Boe per day. In comparison, our production volumes for the twelve months ended December 31, 2010 were 260 MBoe, or 710 Boe per day. The increase in production volumes was primarily due to ongoing waterflood response and the drilling programs in our Oklahoma waterflood units in addition to the acquisitions of interests in various properties located in the Hugoton Basin area. Our average sales price per barrel for oil, excluding commodity derivative contracts, for the twelve months ended December 31, 2011 was $90.45, compared with $73.92 for the twelve months ended December 31, 2010.

Effects of Commodity Derivative Contracts. Due to changes in commodity prices, we recorded a net gain from our commodity hedging program for the twelve months ended December 31, 2011 of approximately $1.3 million, which was composed of a realized loss of $2.1 million and an unrealized gain of $3.4 million. For the twelve months ended December 31, 2010, we recorded a net loss from our commodity hedging program of approximately $0.8 million, which was composed of a realized loss of $0.1 million and an unrealized loss of $0.7 million.

Lease Operating Expenses. Our lease operating expenses were $8.5 million for the twelve months ended December 31, 2011, or $19.56 per Boe, compared to $6.2 million for the twelve months ended December 31, 2010, or $23.99 per Boe. The increase in total lease operating expenses during the twelve months ended December 31, 2011 was primarily attributable to an increase in production resulting from drilling programs and the increase in the number of wells producing. The decrease in lease operating expenses per Boe was due to the increased production for the twelve months ended December 31, 2011. Ad valorem taxes are also reflected in lease operating expenses. Ad valorem taxes are levied on our properties in Colorado and are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts, and a percentage of production equipment value.

Production Taxes. Our production taxes were $1.9 million for the twelve months ended December 31, 2011, or $4.31 per Boe for an effective tax rate of 4.9%, compared to $0.8 million for the twelve months ended December 31, 2010, or $3.16 per Boe for an effective tax rate of 4.5%. The increase in production taxes during the twelve months ended December 31, 2011 was primarily due to the increase in the realized average oil sales price. Production taxes are calculated as a percentage of our oil and natural gas revenues, excluding the effects of our commodity derivative contracts. Although the State of Oklahoma, where most of our properties are located, currently imposes a production tax of 7.2% for oil and natural gas properties and an excise tax of 0.095%, a portion of our wells in Oklahoma currently receive a reduced rate due to the Enhanced Recovery Project Gross Production Tax Exemption.

Depreciation, Depletion and Amortization Expenses. Our depreciation, depletion and amortization expenses on producing properties for the twelve months ended December 31, 2011 were $6.8 million, or $15.66 per Boe produced, compared to $5.2 million, or $20.02 per Boe produced, for the twelve months ended December 31, 2010. The increase in depreciation, depletion and amortization expenses was due to an increase in asset value from acquisition of waterflood units in our Hugoton Basin core area and Southern Oklahoma. The decrease in price per Boe was due to an increase in production.

Impairment of Oil and Natural Gas Properties. During the year ended December 31, 2010, we recorded a non-cash impairment charge of $1.9 million due to a decline in reserve estimates for certain producing properties. There was no impairment charge for the year ended December 31, 2011.

General and Administrative Expenses. Our general and administrative expenses were approximately $3.8 million for the twelve months ended December 31, 2011, or $8.67 per Boe produced compared to $1.4 million for the twelve months ended December 31, 2010 or $5.29 per Boe produced. The increase in general and administrative expenses for the twelve months ended December 31, 2011 resulted primarily from higher compensation costs related to our non-cash equity-based compensation expense, higher professional fees necessary to comply with public reporting requirements, and higher personnel costs related to the hiring of additional staff.

Interest Expense. Our interest expense for the twelve months ended December 31, 2011 was $0.6 million, compared to $0.1 million for the twelve months ended December 31, 2010. The increase was primarily due to increased borrowings on our credit facilities for capital expenditures and acquisitions. In addition, in December 2011, we entered into a new credit facility which resulted in higher average borrowings outstanding.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for oil and natural gas, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

We believe a strong balance sheet is a necessary pre-requisite for creating sustainable growth in unitholder value. Our liquidity position as of December 31, 2012 consisted of approximately $1.1 million of available cash, and $52.0 million of available borrowings under our credit facility. Our primary use of capital has been for the acquisition and development of oil and natural gas properties. As we pursue profitable reserves and production growth, we continually monitor our liquidity and the credit markets. Additionally, we continue to monitor events and circumstances surrounding each of the lenders in our credit facility.

As of December 31, 2012, our $250 million credit facility had a borrowing capacity of $52.0 million ($130.0 million borrowing base less $78.0 million of outstanding borrowings). The borrowing is re-determined on or about April 30 and October 31 of each year, beginning on or about April 30, 2012. In April and November 2012, the borrowing base of our credit facility was increased to $100.0 million and $130.0 million, respectively.

Cash Flow

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

	Year Ended December 31,		
	2012	2011	2010
Operating activities	$ 47,717	$ 24,113	$ 11,798
Investing activities	(72,539)	(42,045)	(22,726)
Financing activities	25,647	17,938	10,387

Operating Activities. Net cash provided by operating activities was approximately $47.7 million, $24.1 million, and $11.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our revenues increased significantly for the year ended December 31, 2012 compared to the year ended December 31, 2011, and when comparing year ended December 31, 2011 to year ended December 31, 2010, primarily due to increased production, favorable commodity pricing, our successful exploitation of our proved reserves, our ability to reduce our per unit operating expenses and our successful acquisition activity. Cash provided by operating activities is impacted by the prices we receive for oil and natural gas sales and production volumes. Our production volumes in the future will in large part be dependent upon the results of past waterflood development activities and results of future capital expenditures. Our future levels of capital expenditures may vary due to many factors, including development and drilling results, oil and natural gas prices, industry conditions, prices and availability of goods and services and the extent to which proved properties are acquired.

Investing Activities. Net cash used in investing activities was approximately $72.5 million, $42.0 million, and $22.7 million for the years ended December 31, 2012, 2011, and 2010, respectively. The increased amount of cash used in investing activities for the years ended December 31, 2012, 2011 and 2010 was primarily due to the acquisition of oil properties and additional working interest in addition to the in-field drilling of our waterflood units.

Financing Activities. Net cash provided by financing activities was approximately $25.6 million, $17.9 million, and $10.4 million for the year ended December 31, 2012, 2011 and 2010, respectively. During the year ended December 31, 2012, we received net proceeds from our credit facility of approximately $33.0 million in addition to proceeds of $20.4 million from the sale of our common units. Conversely, we made distributions to unitholders of approximately $27.7 million. During the year ended December 31, 2011, we received proceeds of $87.4 million from our Initial Public Offering net of offering costs, and net proceeds from our financing arrangements of $39.2 million which were used to fund our drilling activity in Southern Oklahoma and the distribution of $110.9 million to redeem the limited liability company membership units held by certain employees, directors, and non-affiliates in consideration for the merger of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC into our subsidiary at the closing of our Initial Public Offering. For the year ended December 31, 2010, the cash provided by financing activities primarily related to $10.0 million of capital contributions, $5.3 million from borrowings and was used to fund a $4.8 million distribution to certain members.

Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations in order to increase and maintain our production and the size our asset base. The primary purpose of growth capital is to acquire, develop and produce assets that allow us to increase our production levels and asset base. To date, we have funded acquisition transactions through a combination of internal and external finance sources. We expect to finance any significant acquisition of oil and natural gas properties in 2013 through the issuance of equity, debt financing or borrowings under our credit facility.

During June 2012, we completed the acquisition of oil properties located in the Northeastern Oklahoma core area and additional working interests in our existing units in the Southern Oklahoma core area, in unrelated transactions, for approximately $16.4 million and other miscellaneous acquisitions for approximately $0.2 million. The transactions were financed using existing cash and proceeds from our credit facility.

During October 2012, we acquired additional working interests located in our Hugoton Basin core area for approximately $3.7 million. The transaction was financed using proceeds from our credit facility.

During November 2012, we completed the acquisition 100% working interest in certain oil and natural gas properties located in the Hugoton Basin core area for approximately $28.9 million, subject to customary purchase price adjustments. The transactions were financed using proceeds from our credit facility.

In 2012, our capital spending program for the development of our oil and natural gas properties, including projects for our properties acquired in 2012, was approximately $21.6 million. We currently expect 2013 spending for the development, growth and maintenance of our oil and natural gas properties to be approximately

$23.5 million. We will consider adjustments to this capital program based on our assessment of additional development opportunities that are identified during the year and the cash available to invest in our development projects. We are actively engaged in the acquisition of oil and natural gas properties.

Credit Facility

We have a $250.0 million senior secure revolving credit facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiary. 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. At December 31, 2012, we had approximately $78.0 million of borrowings outstanding under the revolving credit facility. The facility requires us and our subsidiary to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0. As of December 31, 2012, we were in compliance with all of the facility's financial covenants.

During 2012, our borrowing based under the credit facility was increased from $75.0 million to $100.0 and from $100.0 million to $130.0 million, in April and November, respectively. Borrowings under the facility may not exceed our current borrowing base of $130.0 million. The borrowing base is determined by the lenders based on our oil and natural gas reserves. The borrowing base is subject to scheduled redeterminations on or about April 30 and October 31 of each year with an additional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract. The borrowing base is determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary.

Borrowings under the credit facility bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of the Royal Bank of Canada, 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 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. For the year ended December 31, 2012, the average effective rate was approximately 2.5%. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

Derivative Contracts

At December 31, 2012, our open commodity derivative contracts were in a net receivable position with a fair value of $4.5 million. All of our commodity derivative contracts are with major financial institutions. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss. As of December 31, 2012, all of our counterparties have performed pursuant to their commodity derivative contracts.

All of our derivative contracts for 2013 and 2014 are either swaps with fixed settlements or collars. In a typical commodity swap agreement we receive the difference between a fixed price per unit of production and a price based on an agreed upon published third-party index, if the index price is lower than the fixed price. If the index price is higher than the fixed price, we pay the difference. By entering into swap agreements, we effectively fix the price that we will receive in the future for the hedged production. Our swaps are settled in cash on a monthly basis. A "collar" is a combination of a put option we purchase and a call option we sell. In a typical collar transaction, if the reference price, based on NYMEX quoted prices, is below the floor price, we receive an amount equal to this difference multiplied by the specified volume. If the reference price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the reference price exceeds the ceiling price, we must pay an amount equal to this difference multiplied by the specified volume.

The following table summarizes, for the periods indicated, our oil swaps and put/call options, or "collars," through December 31, 2014. These transactions are settled based upon the NYMEX-WTI price of oil.

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day
Swaps - 2013	$98.26			1,545
Collars - 2013		$97.67	$108.08	296
Swaps - 2014	$93.71			1,644

Our hedging strategy is to enter into various commodity derivative contracts intended to achieve more predictable cash flows and to reduce exposure to fluctuations in the price of oil. Our hedging program's objective is to protect our ability to make current distributions, and to allow us to be better positioned to increase our quarterly distributions over time, while retaining some ability to participate in upward movements in oil prices. We use a phased approach, looking approximately 36 months forward while targeting a higher hedged percentage in the near 12 months of the period. As of December 31, 2012, we have commodity derivative contracts covering approximately 71% and 59% of our calendar years 2013 and 2014 average daily oil production (as estimated from the projection of our oil production in our audited proved reserves as of December 31, 2012).

We do not specifically designate commodity derivative contracts as cash flow hedges; therefore, the mark-to-market adjustment reflecting the change in the unrealized gains or losses on these 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. Realized gains or losses only arise from payments made or received on monthly settlements or if a commodity derivative contract is terminated prior to its expiration.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2012. The contractual obligations we will actually pay in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

	Obligations Due in Period (in thousands)				
	2013	2014	2015	2016	Total
Long-term debt (1)	$ —	$ —	$ —	$78,000	$78,000
Interest on long-term debt (2)	1,950	1,950	1,950	1,950	7,800
Total	$1,950	$1,950	$1,950	$79,950	$85,800

(1) For purposes of this table, we have assumed that the borrowings under our revolving credit facility as of December 31, 2012 will not be repaid until the maturity date on December 16, 2016.

(2) Interest obligation for borrowings under our credit facility assumes borrowings outstanding at December 31, 2012 will remain outstanding until the maturity date of the facility. The interest obligation is based on a 2.5% borrowing rate at December 31, 2012.

Our ARO is not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our ARO at December 31, 2012 is $2.9 million.

Off–Balance Sheet Arrangements

As of December 31, 2012, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements

No new accounting pronouncements issued or effective during the year ended December 31, 2012 have had or are expected to have a material impact on our consolidated financial statements.

ITEM 7A. Quantitative and Qualitative Disclosure about Market Risk

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business.

The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil production. Realized pricing is primarily driven by the spot market prices applicable to the prevailing price for oil. Pricing for oil has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into commodity derivative contracts with respect to a significant portion of our projected oil production through various transactions that fix the future prices received. These hedging activities are intended to manage our exposure to oil price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

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

The fair value of our oil and natural gas commodity contracts and swaps at December 31, 2012 was a net asset of approximately $4.5 million. A 10% change in oil and natural gas prices with all other factors held constant would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil and natural gas commodity contracts and swaps of approximately ($10.7 million). Please see “Item 8. Financial Statements and Supplementary Data” contained herein for additional information.

Interest Rate Risk

At December 31, 2012, we had debt outstanding of $78.0 million, with an effective interest rate of 2.5%. Assuming no change in the amount outstanding, the impact on interest expense of a 10% increase or decrease in the average interest rate would be approximately $0.2 million on an annual basis. Our revolving credit facility allows borrowings up to $130.0 million at an interest rate ranging from LIBOR plus 1.75% to LIBOR plus 2.75% or the prime rate plus 0.75% to the prime rate plus 1.75% depending on the amount borrowed. The prime rate will be the United States prime rate as announced from time-to-time by the Royal Bank of Canada. Please see “Item 8. Financial Statements and Supplementary Data” contained herein.

Counterparty and Customer Credit Risk

We are subject to credit risk due to the concentration of our revenues attributable to a small number of customers for our current 2013 production. The inability or failure of any of our customers to meet its obligations to us or its insolvency or liquidation may adversely affect our financial results. However, Enterprise, Vitol Inc., and Sunoco each have positive payment histories. As of December 31, 2012, Enterprise and Sunoco each have investment grade credit ratings.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Mid-Con Energy Partners, LP

We have audited the accompanying consolidated balance sheets of Mid-Con Energy Partners, LP (a Delaware limited partnership) and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mid-Con Energy Partners, LP and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

GRANT THORNTON LLP

Tulsa, Oklahoma
March 6, 2013

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

	December 31, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,053	$ 228
Accounts receivable:		
Oil and gas sales	6,413	5,018
Other	603	2,405
Derivative financial instruments	3,679	1,028
Prepaids and other	25	25
Total current assets	11,773	8,704
PROPERTY AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	167,036	97,269
Accumulated depletion, depreciation and amortization	(21,727)	(11,403)
Total property and equipment, net	145,309	85,866
DERIVATIVE FINANCIAL INSTRUMENTS	858	1,505
OTHER ASSETS	650	536
Total assets	$158,590	$ 96,611
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 5,204	$ 4,575
Accrued liabilities	315	138
Other payables	—	1,630
Total current liabilities	5,519	6,343
LONG-TERM DEBT	78,000	45,000
ASSET RETIREMENT OBLIGATIONS	2,890	1,919
EQUITY, per accompanying statements:		
Partnership equity		
General partner interest	1,814	1,299
Limited partners-18,990,849 and 17,640,000 units issued and outstanding as of December 31, 2012 and 2011, respectively	70,367	42,050
Total equity	72,181	43,349
Total liabilities and equity	$158,590	$ 96,611

See accompanying notes to consolidated financial statements

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

	Mid-Con Energy Partners, LP		
	Year Ended December 31,		
	2012	2011	2010
Revenues:			
Oil sales	$60,887	$36,813	$16,853
Natural gas sales	674	1,218	1,418
Realized gain (loss) on derivatives, net	3,710	(2,157)	(90)
Unrealized gain (loss) on derivatives, net	2,004	3,437	(707)
Total revenues	67,275	39,311	17,474
Operating costs and expenses:			
Lease operating expenses	10,948	8,491	6,237
Oil and gas production taxes	1,965	1,869	822
Impairment of proved oil and gas properties	1,296	—	1,886
Dry holes and abandonments of unproved properties	—	813	1,418
Depreciation, depletion and amortization	10,324	7,160	5,851
Accretion of discount on asset retirement obligations	126	78	127
General and administrative	11,000	3,767	1,376
Total operating costs and expenses	35,659	22,178	17,717
Income (loss) from operations	31,616	17,133	(243)
Other income (expense):			
Interest income and other	10	216	218
Interest expense	(1,764)	(578)	(98)
Gain on sale of assets	—	1,621	354
Other revenue and expenses, net	—	576	847
Total other income (expense)	(1,754)	1,835	1,321
Net income	$29,862	$18,968	$ 1,078
Computation of net income per limited partner unit:			
General partners' interest in net income	$ 584	$ 379	$ 22
Limited partners' interest in net income	$29,278	$18,589	$ 1,056
Net income per limited partner unit (basic and diluted)	$ 1.62	$ 1.05	$ 0.06
Weighted average limited partner units outstanding: (basic and diluted)	18,049	17,640	17,640

See accompanying notes to consolidated financial statements

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

	Mid-Con Energy Partners, LP		
	Year Ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities:			
Net income	$ 29,862	$ 18,968	$ 1,078
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	10,324	7,160	5,851
Debt placement fee amortization	131	—	—
Accretion of discount on asset retirement obligations	126	78	127
Impairment of proved oil and gas properties	1,296	—	1,886
Dry holes and abandonments of unproved properties	—	813	1,418
Unrealized loss (gain) on derivative instruments, net	(2,004)	(3,437)	707
Gain on sale of assets	—	(1,621)	(354)
Equity-based compensation	6,323	1,671	—
Changes in operating assets and liabilities:			
Accounts receivable	(1,395)	(4,454)	(1,473)
Other receivables	(603)	—	—
Prepaid and other	2,159	415	(107)
Accounts payable and accrued liabilities	1,498	4,608	1,179
Revenues payable	—	32	46
Advance billings and other	—	(120)	1,440
Net cash provided by operating activities	47,717	24,113	11,798
Cash Flows from Investing Activities:			
Additions to oil and gas properties	(23,960)	(32,654)	(15,936)
Additions to other property and equipment	—	(679)	(922)
Acquisitions of oil and natural gas properties	(48,579)	(16,026)	(6,484)
Proceeds from sale of other property and equipment	—	1,219	608
Proceeds from sale of investment in subsidiary, net of cash sold	—	2,095	8
Proceeds from sale of property and equipment to subsidiary, net of cash sold	—	4,000	—
Net cash used in investing activities	(72,539)	(42,045)	(22,726)
Cash Flows from Financing Activities:			
Proceeds from line of credit	80,800	68,564	15,760
Payments on line of credit	(47,800)	(29,385)	(10,500)
Borrowings on note payable	—	412	10
Payments on note payable	—	(84)	(94)
Owners' contributions	—	—	10,000
Proceeds from initial public offering, net of discount	—	87,397	—
Distributions paid	(27,705)	(110,937)	(4,785)
Repurchase of common units	—	(1)	(4)
Issuance of common units	20,352	1,972	—
Net cash provided by financing activities	25,647	17,938	10,387
Net increase (decrease) in cash and cash equivalents	825	6	(541)
Beginning cash and cash equivalents	228	222	763
Ending cash and cash equivalents	$ 1,053	$ 228	$ 222
Supplemental Cash Flow Information:			
Cash paid for interest	$ 1,561	$ 535	$ 95
Non-Cash Investing and Financing Activities:			
Accrued capital expenditures - oil and gas properties	$ 1,005	$ 3,331	$ 1,209
Deferred gain on sale of property and equipment to subsidiary	$ —	$ 1,208	$ —
Notes receivable from officers and employees	$ —	$ —	$ 635

See accompanying notes to consolidated financial statements

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

	Contributed Capital	Notes Receivable from Officers, Director and Employees	Accumulated Earnings/ (Deficit)	Total Owners' Equity
Balance, December 31, 2009	$47,073	$ (1,198)	$ (9,096)	$ 36,779
Contributions	10,646	(646)	—	10,000
Distributions	(4,785)	—	—	(4,785)
Repurchase of common units	(15)	11	—	(4)
Interest in partnership sold	4	—	—	4
Net income	—	—	1,078	1,078
Balance December 31, 2010	$52,923	$ (1,833)	$ (8,018)	$ 43,072
Contributions	1,350	(106)	—	1,244
Repurchase of common units	(4)	3	—	(1)
Equity-based compensation	1,671	—	—	1,671
Net income	—	—	17,927	17,927
Balance, November 30, 2011	$55,940	$ (1,936)	$ 9,909	$ 63,913

	General	Limited Partner		Total
	Partner	Units	Amount	Equity
Combination transaction with Mid-Con Energy I, LLC and Mid-Con Energy II, LLC	$ 1,278	12,240	$ 62,635	$ 63,913
Issuance of common units in initial public offering	—	5,400	87,395	87,395
Distribution to unitholders of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC	—	—	(109,000)	(109,000)
Net income	21	—	1,020	1,041
Balance, December 31, 2011	$ 1,299	17,640	$ 42,050	$ 43,349
Equity-based compensation	119	351	6,204	6,323
Issuance of common units	378	1,000	19,974	20,352
Distributions	(537)	—	(27,168)	(27,705)
Net income	555	—	29,307	29,862
Balance, December 31, 2012	$ 1,814	18,991	$ 70,367	$ 72,181

See accompanying notes to consolidated financial statements

Mid-Con Energy Partners, LP and subsidiaries
Notes to Consolidated Financial Statements

Note 1. Organization and Nature of Operations

Mid-Con Energy Partners, LP ("Company, we, us") is a publicly held limited partnership that engages in the acquisition, development and production of oil and natural gas properties in North America, with a focus on the Mid-Continent region of the United States. We completed our initial public offering ("Initial Public Offering") in December 2011 and our common units are traded on the NASDAQ Global Select Market under the symbol "MCEP". Our general partner is Mid-Con Energy GP, LLC a Delaware limited liability company.

Note 2. Summary of Significant Accounting Policies

Basis of presentation and principles of consolidation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2012 and 2011. These financial statements also include the results of our operations, cash flows and changes in equity for the years ended December 31, 2012, 2011 and 2010.

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All intercompany transactions and account balances have been eliminated. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or equity.

We operate oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. We evaluate performance based on one business segment, as there are not different economic environments within the operation of the oil and natural gas properties.

Use of estimates

The preparation of financial statements 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. Significant items subject to those estimates and assumptions include: depletion of oil and gas properties which is determined using estimates of proved oil and 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 and unproved oil and 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, asset retirement obligations, fair value of business combinations and fair value of derivative financial instruments.

Cash and cash equivalents

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

Accounts receivable

Accounts receivable are generated from the sale of oil and natural gas to various customers. We routinely assess the financial strength of our customers and bad debts are recorded based on an account–by–account review after all means of collection have been exhausted, and the potential recovery is considered remote. As of December 31, 2012 and 2011, we did not have any reserves for doubtful accounts, and we did not incur any expenses related to bad debts in any period presented.

Revenue recognition

We follow the sales method of accounting for crude oil and natural gas revenues. Under this method, revenues are recognized based on our share of actual proceeds from oil and gas sold to purchasers. Natural gas revenues would not have been significantly altered for the period presented had the entitlements method of recognizing natural gas revenues been utilized. If reserves are not sufficient to recover natural gas overtake positions, a liability is recorded. We had no significant natural gas imbalances at December 31, 2012 or 2011.

Oil and natural gas properties

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

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

Costs of significant nonproducing 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 depreciation 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 gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved and risk-adjusted probable and possible oil and gas reserves over the economic life of the reserves based on our expectations of future oil and gas prices and costs. We review our oil and gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base.

For the year ended December 31, 2012 we recorded an impairment charge of approximately $1.3 million, approximately $1.1 million of the impairment charge relates to our gas producing properties. For the year ended December 31, 2011 no impairment charge was recorded. For the year ended December 31, 2010 we recorded an impairment charge of approximately $1.9 million, approximately $0.6 million of the impairment charge was associated with properties that were sold to the Mid-Con Affiliates in 2011. All of the impairment charges are due to a decline in estimated proved and probable reserve values. These non-cash charges are included in the "impairment of proved oil and gas properties" line item in the accompanying statements of operations. The fair value of the properties was measured by estimated cash flow reported in the audited reserve report. This report was based upon future oil and natural gas prices, which are based on observable inputs adjusted for basis differentials, which are Level 3 inputs in the fair value hierarchy described in Note 6. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flow to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of reserves, future operating and development costs, future commodity prices and market-based weighted average cost of capital rate. The underlying commodity prices embedded in our estimated cash flow are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Furthermore, significant assumptions in valuing the proved reserves included the reserve quantities, anticipated drilling and operating costs, anticipated production taxes and future expected oil and natural gas prices. Cash flow estimates for the impairment testing excluded derivative instruments used to mitigate the risk of lower future oil and natural gas prices. The impairments were caused by the decrease in reserves of our natural gas properties in 2012 and by below expected performance from some of the waterflood units and other producing properties in 2010. These impairments have no impact on our cash flow, liquidity position, or debt covenants.

Unproved oil and gas properties are each periodically assessed for impairment by comparing their costs to their estimated values on a project-by-project basis. The estimated value is affected by the results of exploration activities, future drilling plans, commodity price outlooks, planned future sales or expiration of all or a portion of leases on such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we recognize an impairment loss at that time. We did not have any abandonment expenses for the year ended December 31, 2012 and we recognized approximately $0.8 million and $1.4 million as abandonment expenses for the years ended December 31, 2011 and 2010, respectively, related to its unproved oil and gas properties.

Other property and equipment

Other property and equipment is stated at historical cost and is comprised of software, vehicles, office equipment, and field service equipment. Costs incurred for normal repairs and maintenance are charged to expense as incurred, unless they extend the useful life of the asset. Depreciation is calculated using the straight-line method based on estimated useful lives of the assets ranging from three to fifteen years and is included in the accumulated depreciation, depletion and amortization totals. All of the other property and equipment was sold to one of our Affiliates at June 30, 2011. Consequently, there was no depreciation expense related to other property and equipment for the year ended December 31, 2012. For the years ended December 31, 2011 and 2010, depreciation expense related to other property and equipment totaled approximately $0.3 million and $0.6 million, respectively.

Asset retirement obligations

We have obligations under our lease agreements and federal regulations to remove equipment and restore land at the end of oil and natural gas production operations. These asset retirement obligations (“ARO”) are primarily associated with plugging and abandoning wells. Determining the future restoration and removal requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. We are required to record the fair value of a liability for an ARO in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. We typically incur this liability upon acquiring or drilling a well. Over time, the liability is accreted each period toward its future value and the capitalized cost is depleted as a component of development costs. Upon settlement of the liability, a gain or loss is recognized to the extent the actual costs differ from the recorded liability.

Inherent to the present value calculation are numerous estimates, assumptions 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. 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. Increases in the discounted retirement obligation liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the statements of operations.

Derivatives and hedging

We monitor our exposure to various business risks, including commodity price and interest rate risks, and use derivatives to manage the impact of certain of these risks. Our policies do not permit the use of derivatives for speculative purposes. We use energy derivatives for the purpose of mitigating risk resulting from fluctuations in the market price of oil and natural gas. All derivative instruments are recorded on the balance sheet as either assets or liabilities at fair value.

None of our derivatives held during 2012 and 2011 were designated as hedges for financial statement purposes; therefore, the adjustments to fair value are included in net income. Realized and unrealized gains and losses on derivatives are included in cash flow from operating activities.

Other revenue and expense, net

Prior to June 30, 2011, we received fees for the operation of jointly-owned oil and gas properties and recorded such reimbursements as reductions of other revenue and expense, net. Such fees totaled approximately $2.1 million and $3.1 million for the years ended December 31, 2011 and 2010, respectively. These fees are now received by our affiliate, Mid-Con Energy Operating, Inc.

Equity-based compensation

The cost of employee services received in exchange for equity instruments is measured based on the grant-date fair value of compensation expense over the requisite service period (often the vesting period). Awards subject to performance criteria vest when it is probable that the performance criteria will be met. Compensation for these awards is recorded upon vesting, based on their grant-date fair value. Generally, no compensation expense is recognized for equity instruments that do not vest. The equity-based compensation expense was not significant for any periods prior to 2011. We recorded equity-based compensation expense of $6.5 million which includes non-cash equity based compensation of $6.3 million and cash-based compensation for employer payroll taxes reimbursed to Mid-Con Energy Operating of $0.2 million, and $1.7 million for the years ended December 31, 2012 and 2011, respectively.

Income taxes

We are a partnership that is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, our taxable income or loss is includable in the federal income tax returns of our partners. 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.

Net income per limited partner unit

Net income per limited partner unit is determined by dividing net income available to the limited partners, after deducting the general partner’s interest in net income, by the weighted average number of limited partner units outstanding for the period.

Business segment reporting

We operate in one reportable segment engaged in the development, exploitation and production of oil and natural gas properties. All of our operations are located in the United States.

New accounting pronouncements

In December 2011, the FASB issued ASU No. 2011-11, *Disclosures about Offsetting Assets and Liabilities.* This amendment affects all entities that have financial instruments and derivative instruments that are either offset or subject to an enforceable master netting arrangement or similar agreement. The amendment requires an entity to disclose information about offsetting and related arrangements to enable user of its financial statements to understand the effect of those arrangements on its financial position. The provisions of this amendment are applicable to annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. We plan to adopt this update on January 1, 2013 and do not expect this update to have a significant impact on the consolidated financial statements.

No other new accounting pronouncements issued or effective during the year ended December 31, 2012 had or are expected to have a material impact on our unaudited condensed financial statements.

Note 3. Acquisitions

During June 2012, we acquired certain oil properties located in the Northeastern Oklahoma core area, and additional working interests in our existing units in the Southern Oklahoma core area, in unrelated transactions. The results of operations of these properties have been included in the consolidated financial statements since the acquisition date. We paid approximately $16.4 million in aggregate consideration for these properties, subject to customary purchase price adjustments, and the transaction was accounted for under the acquisition method. The transactions were financed using existing cash and proceeds from our credit facility.

During October 2012, we acquired additional working interests in our War Party Unit I and War Party Unit II located in the Hugoton Basin core area. The results of operations of these properties have been included in the consolidated financial statements since the acquisition date. We paid approximately $3.7 million in consideration for the interests and the transaction was accounted for under the acquisition method. The transactions were financed using proceeds from our credit facility.

During November 2012, we acquired a 100% working interest in the Clawson Ranch Waterflood Unit ("Clawson Ranch") in our Hugoton Basin core area from multiple parties. The results of operations of these properties have been included in the consolidated financial statements since the acquisition date. We paid approximately $28.9 million in consideration for the properties and interests, subject to customary purchase price adjustments, and the transaction was accounted for under the acquisition method. The transactions were financed using proceeds from our credit facility. The purchase price for these properties represented approximately 30% of the total value of Mid-Con Energy Partners, LP assets as of December 31, 2011. The recognized fair values of the identifiable assets of the Clawson Ranch acquired and liabilities assumed in connection with the acquisition are as follows (in thousands):

Fair Value of net assets:	
Oil and gas properties	$29,105
Total assets acquired	$29,105
Fair Value of net liabilities assumed:	
Asset retirement obligation	249
Net assets acquired	$28,856

The following table reflects pro forma revenues, net income and net income per limited partner unit for the years ended as if the Clawson Ranch acquisition had taken place on January 1, 2011. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the periods presented or that may be obtained in the future.

	2012	2011
Revenues	73,443	47,677
Net income	32,112	22,408
Net income per limited partner unit		
Basic and diluted	$ 1.74	$ 1.24

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, Inc. (“Mid-Con Energy Operating”), who perform services for us. The Long-Term Incentive Program is administered by the Board of Directors of the general partner. The Long-Term Incentive Program allows for the award of unit options, unit appreciation rights, restricted units, phantom units, distribution equivalent rights granted with phantom units, and other types of awards. The Long-Term Incentive Program permits the grant of awards covering an aggregate of 1,764,000 units under the Form S-8 we filed with the SEC on January 25, 2012. As of December 31, 2012, there were 1,413,151 units available for issuance under the Plan.

The weighted average grant-date fair value of unrestricted unit grants and restricted units granted was $20.66 during the year ended December 31, 2012. There were no restricted units that granted during the year 2012. As of December 31, 2012 there was approximately $0.8 million of unrecognized compensation cost related to nonvested units. The cost is expected to be recognized over a weighted average period of approximately 2.3 years.

In January 2012, we issued 125,000 unrestricted common units (“URUs”) to employees, officers, directors and consultants of our general partner and affiliates. Also, in January 2012, we issued 24,561 restricted common units (“RUs”) that have a three- year vesting period. The fair market value of both the URUs and RUs was based on the closing price of our common units at the date of the awards, which was $20.90 per unit.

In July 2012, we issued 112,500 unrestricted common units (“URUs”) to employees, officers, directors and consultants of our general partner and affiliates. Also, in July 2012, we issued 38,097 restricted common units (“RUs”) that have a three-year vesting period. The fair market value of both the URUs and RUs was based on the closing price of our common units at the date of the awards, which was $21.50 per unit. During the third quarter 2012, there were 7,309 RUs forfeited.

In November 2012, we issued 58,200 unrestricted common units (“URUs”) to employees, officers, directors and consultants of our general partner and affiliates. The fair market value of both these URUs was based on the closing price of our common units at the date of the awards, which was $17.87 per unit. During the fourth quarter 2012, there were 200 RUs forfeited.

The RUs are subject to forfeiture and we assume a 10% forfeiture rate for the RUs to estimate our equity-based compensation expense. As of December 31, 2012, there were 7,509 RUs forfeited. We recognized $6.5 million and $1.7 million of equity-based compensation expense for the years ended December 31, 2012 and 2011, respectively. These costs are reported as a component of general and administrative expense in our consolidated statements of operations. The equity-based compensation expense was not significant for any period prior to 2011.

Note 5. Derivative Financial Instruments

Our risk management program is intended to reduce our exposure to commodity prices and interest rates and to assist with stabilizing cash flows. Accordingly, we utilize derivative financial instruments to manage our exposure to commodity price fluctuations and fluctuations in location differences between published index prices and the NYMEX futures prices. Our policies do not permit the use of derivatives for speculative purposes.

At December 31, 2012 and 2011 our open positions consisted of crude oil price collar contracts and crude oil price swap contracts. Under commodity swap agreements, we exchange a stream of payments over time according to specified terms with another counterparty. In a typical commodity swap agreement, we agree to pay an adjustable or floating price tied to an agreed upon index for the oil commodity and in return receive a fixed price based on notional quantities. A collar is a combination of a put purchased by a party and a call option sold by the same party. In a typical collar transaction, if the floating price based on a market index is below the floor price, we receive from the counterparty an amount equal to this difference multiplied by the specified volume. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty an amount equal to the difference multiplied by the specific quantity.

We have elected not to designate any of our positions as cash flow hedges for accounting purposes and, accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the statement of operations. Pursuant to the accounting standard that permits netting of assets and liabilities where the right of offset exists, we present the fair value of derivative financial instruments on a net basis.

At December 31, 2012 we had the following oil derivative open positions:

Period Covered	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2013	$98.26			1,545	
Collars - 2013		$97.67	$108.08	296	WTI
Swaps - 2014	$93.71			1,644	

At December 31, 2012, we recorded the estimated fair value of the derivative contracts as a $0.9 million long-term asset and a $3.7 million short-term asset.

At December 31, 2011 we had the following oil derivative open positions:

Period Covered	Average Fixed Price	Average Floor Price	Average Ceiling Price	Total Bbls Hedged/day	NYMEX Index
Swaps - 2012	$101.21			951	
Collars - 2012		$100.00	$117.00	197	WTI
Swaps - 2013	$100.20			460	
Collars - 2013		$100.00	$111.00	197	WTI

At December 31, 2011, we recorded the estimated fair value of the derivative contracts as a $1.5 million long-term asset and a $1.0 million short-term asset.

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

The fair value and location of our derivatives in our condensed consolidated balance sheets was as follows:

	Asset Derivatives		Liability Derivatives	
	December 31,		December 31,	
	2012	2011	2012	2011
Derivative financial instruments - current asset	$3,679	$1,028	$—	$—
Derivative financial instruments - long-term asset	858	1,505	—	—
	$4,537	$2,533	$—	$—

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

	December 31,		
	2012	2011	2010
Realized gain (loss) on derivatives, net	$3,710	$(2,157)	$ (90)
Unrealized gain (loss) on derivatives, net	2,004	3,437	(707)
	$5,714	$ 1,280	$(797)

Note 6. Fair Value Disclosures

Fair value of financial instruments

The carrying amounts reported in the balance sheet for cash, accounts receivable, accounts payable and derivative financial instruments approximate their fair values. The carrying amount of long-term debt under our credit facility approximates fair value because the credit facility's variable interest rates resets frequently and approximates current market rates available to us.

We account for our oil and gas commodity derivatives at fair value. The fair value of derivative financial instruments is determined utilizing NYMEX closing prices for the contract period.

Fair value measurements

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

Our 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.

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. 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, 2012 and 2011:

	Level 1	Level 2	Level 3
		(in thousands)	
December 31, 2012			
Assets and Liabilities Measured as Fair Value on a Recurring Basis			
- Derivative financial instrument- asset	$—	$4,537	$ —
Assets and Liabilities Measured as Fair Value on a Nonrecurring Basis			
- Asset retirement obligations	$—	$ —	$ 845
- Impairment of proved oil and gas properties	$—	$ —	$1,296
December 31, 2011			
Assets and Liabilities Measured as Fair Value on a Recurring Basis			
- Derivative financial instrument- asset	$—	$2,533	$ —
Assets and Liabilities Measured as Fair Value on a Nonrecurring Basis			
- Asset retirement obligations	$—	$ —	$ 717

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 techniques or related inputs for the years ended December 31, 2012 and 2011.

Assets and liabilities measured at fair value on a nonrecurring basis

We estimate the fair value of the AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note 7 for a summary of changes in AROs.

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 of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset and reduces the carrying amount of the asset. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. For the year ended December 31, 2012 we recorded an impairment charge of approximately $1.3 million, approximately $1.1 million of the impairment charge relates to our gas producing properties. For the year ended December 31, 2011 no impairment charge was recorded. For the year ended December 31, 2010, we recorded an impairment charge of approximately $1.9 million, approximately $0.6 million of the impairment charge was associated with properties that were sold to the Mid-Con Affiliates in 2011. All of the impairment charges are due to a decline in estimated proved and probable reserve values.

Note 7. Asset Retirement Obligations

AROs are recorded as a liability at their estimated present value at the various assets' inception, with the offsetting charge to oil and gas properties. Periodic accretion of the discounted estimated liability is recorded in the 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.

Our AROs represent the estimated present value of the amount we will incur to plug, abandon and remediate its producing properties at the end of their production lives, in accordance with applicable state laws. We determine our ARO by calculating the present value of estimated cash flow related to the liability. Each year we review and to the extent necessary, revise our ARO estimates.

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

	Year Ended December 31,		
	2012	2011	2010
		(in thousands)	
Asset retirement obligation - beginning of period	$1,919	$ 2,148	$1,737
Liabilities incurred for new wells and interests	636	370	265
Disposition of wells	—	(1,024)	(35)
Revision of estimates	209	347	54
Accretion expense	126	78	127
Asset retirement obligation - end of period	$2,890	$ 1,919	$2,148

Note 8. Debt

We have a $250.0 million senior secure revolving credit facility that expires in December 2016. Borrowings under the facility are secured by liens on not less than 80% of our assets and the assets of our subsidiary. 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. At December 31, 2012, we had approximately $78.0 million of borrowings outstanding under the revolving credit facility. The facility requires us and our subsidiary to maintain a leverage ratio of Consolidated Funded Indebtedness to Consolidated EBITDAX (as defined in the facility) of not more than 4.0 to 1.0, and a current ratio of not less than 1.0 to 1.0.

The credit facility includes customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and payments. 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, 2012, we were in compliance with all debt covenants.

During the 2012 borrowing base determinations, our borrowing base under the credit facility was increased from $75.0 million to $100.0 and from $100.0 million to $130.0 million, in April and November, respectively. Borrowings under the facility may not exceed our current borrowing base of $130.0 million. The borrowing base is determined by the lenders based on our oil and natural gas reserves. The borrowing base is subject to scheduled redeterminations on or about April 30 and October 31 of each year with an additional redetermination during the period between each scheduled borrowing base determination, either at our request or at the request of the lenders. An additional borrowing base redetermination may be made at the request of the lenders in connection with a material disposition of our properties or a material liquidation of a hedge contract. The borrowing base is determined by our lenders based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary.

Borrowings under the credit agreement bear interest at a floating rate based on, at our election: (i) the greater of the prime rate of the Royal Bank of Canada, 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 0.75% to 1.75% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. For the year ended December 31, 2012, the average effective rate was approximately 2.5%. The unused portion of the borrowing base is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

Note 9. Commitment and Contingencies

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

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

Our general partner has entered into employment agreements with certain executive officers. The employment agreements provide for a term that commenced on August 1, 2011 and expires on August 1, 2014, unless earlier terminated, with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities, and authority as the board of directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him. The agreement stipulates that if there is a change of control, termination of employment with cause or without cause, or death of the executive certain payments will be made to the executive officer. These payments, depending on the reason for termination, currently range from $1.6 million to $1.9 million, including the value of vesting of any outstanding units.

Note 10. Equity

Common Units

At December 31, 2012 and 2011, Partnership’s equity consisted of 18,990,849 and 17,640,000 common units, respectively, representing approximately a 98% limited partnership interest in us.

On October 22, 2012, we sold 4,600,000 common units to the public a price of $21.20 per common unit. 1,000,000 common units were sold by us, and 3,600,000 common units were sold by Yorktown Energy Partners, VI, L.P., Yorktown Energy Partners VII, L.P., and Yorktown Energy Partners VIII, L.P. Proceeds from our 1,000,000 common units offering, net of underwriting discounts and expenses, were approximately $20.4 million. We did not receive any proceeds from the 3,600,000 common units sold by Yorktown.

Cash Distributions

We intend to make regular cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our credit facility prohibits us from making cash distributions if any potential default or event of default, as defined in our credit facility, occurs or would result from the cash distribution.

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. Our cash distribution policy reflects a basic judgment that our unitholders will be better served by us distributing our available cash, after expenses and reserves, rather than retaining it.

The following sets forth the distributions we paid during the year ended December 31, 2012:

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 13, 2012	December 21, 2011 – December 31, 2011	$0.057	$ 1,034(1)
May 14, 2012	January 1, 2012 – March 31, 2012	0.475	8,622
August 14, 2012	April 1, 2012 – June 30, 2012	0.475	8,692
November 14, 2012	July 1, 2012 – September 30, 2012	0.485	9,357(2)
			$27,705

(1) The distribution represented a proration of initial quarterly distribution of $0.475 per unit.
(2) The distribution represented an increase of $0.01 per unit from the previous quarter.

On January 23, 2013, the board of directors declared a quarterly cash distribution for the fourth quarter of 2012 of $0.495 per unit, which was paid on February 14, 2013 to unitholders of record at the close of business on February 7, 2013. The aggregate amount of the distribution was approximately $9.7 million.

Allocations of Net Income (Loss)

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

Note 11. Related Party Transactions

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. We, our general partner and its affiliates have entered into the various documents and agreements, which are described below.

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. The operational services include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. At December 31, 2012 and 2011, we reimbursed Mid-Con Energy Operating approximately $2.9 million and $0.2 million for direct expenses.

Assignment, Bill of Sale and Conveyance Agreement

We entered into an assignment, bill of sale and conveyance agreement on December 20, 2011 pursuant to which J&A Oil Company, a company controlled by Charles R. Olmstead and Jeffrey R. Olmstead, and Charles R. Olmstead, in his individual capacity, contributed to us certain working interests in the Cushing Field and J&A Oil Company contributed to us its interests in certain derivative contracts for aggregate consideration of approximately $6.0 million.

Contribution, Conveyance, Assumption and Merger Agreement

We entered into a contribution, conveyance, assumption and merger agreement on December 20, 2011 pursuant to which Mid-Con Energy I, LLC and Mid-Con Energy II, LLC merged into our subsidiary, Mid-Con Energy Properties, and our general partner made a contribution to us. The contribution, conveyance, assumption and merger agreement provided for the Founders, Yorktown, our executive officers, employees and other individual entities, as the owners of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC, to receive consideration that included a combination of common units and cash from the proceeds of our public offering and for our general partner to receive a 2.0% general partner interest in us. All of the transaction expenses incurred in connection with these transactions were paid from proceeds of our Initial Public Offering.

Notes Receivable from Officers, Director and Employees

In the aggregate at December 31, 2010, we had notes receivable from officers, a director and employees of $1.8 million plus accrued interest of $0.2 million. The notes matured when our registration statement filed in connection with our Initial Public Offering was declared effective. All such notes receivable were originally issued in conjunction with purchases of the membership units in Mid-Con Energy I, LLC and Mid-Con Energy II, LLC and performance under these notes was secured by security interests granted to us in all of the membership units purchased. Additionally, we had full recourse against the assets of the officers, director and employees for collection of the amounts due upon the occurrence of a default that was not remedied. All of the notes were repaid in connection with our Initial Public Offering.

Other Transactions with Related Persons

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies, or COPAS, fee). We and those third parties will also pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements.

At December 31, 2012 we had a payable to Mid-Con Energy Operating of approximately $3.0 million which is comprised of a joint interest billing payable of approximately $2.7 million and a payable for operating services of approximately $0.3 million. These amounts are included in the Accounts payable in our Consolidated Balance Sheets.

Note 12. Credit Risk

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. The percentage of revenue derived by customers that accounted for 10% or more of consolidated total revenues is presented below. No other customer accounted for more than 10% of our consolidated total revenues for 2012, 2011 or 2010.

For the year ended December 31, 2012, purchases by Enterprise Crude Oil, LLC ("Enterprise"), Vitol Inc., Crude Oil Marketing ("Vitol") and a subsidiary of Sunoco Logistics Partners L.P. ("Sunoco Logistics") accounted for 32%, 28%, and 21%, respectively of our total sales revenues. Vitol represented 52% of our outstanding oil and natural gas accounts receivable at December 31, 2012. Enterprise and Sunoco Logistics did not have any outstanding receivables at the December 31, 2012 because their contracts had expired during the year 2012. We have subsequently entered into an agreement with Enterprise beginning January 2013 to begin purchasing our oil in the Southern Oklahoma core area.

For the year ended December 31, 2011 a subsidiary of Sunoco Logistics Partners L.P. ("Sunoco Logistics"), ScissorTail Energy, LLC and Teppco Crude Oil, LLC accounted for 86%, 9% and 3%, respectively of our total sales revenues. These purchasers represented 88%, 2% and 9%, respectively, of our outstanding oil and natural gas accounts receivable at December 31, 2011.

For the year ended December 31, 2010, purchases by Sunoco Logistics, ScissorTail Energy, LLC and Teppco Crude Oil, LLC accounted for 76%, 8% and 5%, respectively of our total sales revenues.

We believe that the loss of any one purchaser would not have an adverse effect on our ability to sell its oil and gas production because we believe market conditions are such that we could sell to other purchasers at market-based prices. We have not experienced any significant losses due to uncollectible accounts receivable from these purchasers.

Note 13. Employee Benefit Plans

In 2011, our general partner adopted the Mid-Con Energy Partners, LP Long-Term Incentive Program which is intended to promote the interests of the partnership by providing to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating, 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 other affiliates, including Mid-Con Energy Operating, to attract and retain the services of individuals who are essential for the growth and profitability of the partnership and to encourage them to devote their best efforts to advancing the business of the partnership.

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

The type of awards that may be granted under the Long-Term Incentive Program are restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards. The maximum number of our common units that are currently authorized to be awarded under the Plan is 1,764,000 million units. As of December 31, 2012 there were 1,413,151 units available for issuance.

Note 14. Income Taxes

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

Note 15. Subsequent Events

On December 21, 2012, our former Chief Engineer, Robbin W. Jones resigned from his position effective January 21, 2013. Mr. Jones joined the Mid-Con Affiliates in March 2005 and had been our Chief Engineer since December 2011.

On January 23, 2013, the board of directors declared a quarterly cash distribution for the fourth quarter of 2012 of $0.495 per unit, or $1.98 on an annualized basis, an increase of $0.01 from the previous quarter, which was paid on February 14, 2013 to unitholders of record as of the close of business on February 7, 2013. The aggregate amount of the distribution was approximately $9.7 million.

Also, on January 23, 2013, the board of directors of our general partner authorized the issuance of 239,501 common units to certain employees and consultants of our affiliates and certain directors and founders of our general partner.

Note 16. Supplementary Information

Quarterly data (unaudited)

	Quarters Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In thousands, except per unit amounts)			
2012				
Oil and natural gas sales	$15,507	$13,844	$15,048	$17,162
Realized gain (loss) on oil derivatives	(134)	903	1,211	1,730
Unrealized gain (loss) on oil derivatives	(4,773)	14,514	(6,103)	(1,634)
Total revenues and other	10,600	29,261	10,156	17,258
Total expenses (1)	8,938	6,833	11,293	10,349
Net income (loss)	1,662	22,428	(1,137)	6,909
Net income (loss) per unit:	1,629	21,984	(1,115)	6,774
Basic and diluted	$ 0.09	$ 1.23	$ (0.06)	$ 0.36
2011				
Oil and natural gas sales	$ 7,157	$ 9,110	$ 9,775	$11,989
Realized gain (loss) on oil derivatives	(83)	(631)	(84)	(1,359)
Unrealized gain (loss) on oil derivatives	(1,153)	2,198	8,354	(5,962)
Total revenues and other	5,921	10,677	18,045	4,668
Total expenses (1)	4,139	3,823	4,975	7,570
Net income (loss)	1,970	8,276	11,706	(2,984)
Net income (loss) per unit:	1,931	8,110	11,472	(2,924)
Basic and diluted	$ 0.11	$ 0.46	$ 0.65	$ (0.17)

(1) Includes the following expenses: lease operating, production taxes, dry holes and abandonments, geological and geophysical, depreciation, depletion and amortization, accretion, and general and administrative.

Supplementary oil and natural gas activities

	Year Ended December 31,		
	2012	**2011**	**2010**
		(in thousands)	
Property acquisition costs:			
Proved	$48,578	$15,729	$ 6,483
Unproved	—	—	1
Exploration	—	—	912
Development	21,639	30,754	16,843
Asset retirement obligations	679	686	353
Total costs incurred	$70,896	$47,169	$24,592

Estimated proved oil and natural gas reserves (unaudited)

The proved oil and gas reserves for the years ended December 31, 2012, and 2011 were prepared by our reservoir engineers and audited by Cawley, Gillespie & Associates, Inc., independent third party petroleum consultants. These reserve estimates have been prepared in compliance with the rules of the SEC. We emphasize that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates are expected to change as future information becomes available. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, are presented below for the periods indicated:

	Oil (MBbls)	Gas (MMcf)	MBoe (1)
Proved developed and undeveloped reserves:			
As of December 31, 2009	6,199	809	6,335
Revisions of previous estimates	(469)	728	(348)
Extensions, discoveries and other additions	765	—	765
Purchases of minerals in place	740	—	740
Production	(228)	(191)	(261)
As of December 31, 2010	7,007	1,346	7,231
Revisions of previous estimates	740	(370)	678
Extensions, discoveries and other additions	1,704	—	1,704
Purchases of minerals in place	971	140	994
Sales of minerals in place	(79)	(276)	(124)
Production	(407)	(164)	(434)
As of December 31, 2011	9,936	676	10,049
Revisions of previous estimates	(784)	(143)	(808)
Extensions, discoveries and other additions	1,572	—	1,572
Purchases of minerals in place	3,028	18	3,031
Production	(678)	(122)	(698)
As of December 31, 2012	13,074	429	13,146
Proved developed reserves:			
December 31, 2009	2,513	809	2,649
December 31, 2010	3,601	1,346	3,825
December 31, 2011	6,835	676	6,948
December 31, 2012	8,727	429	8,799
Proved undeveloped reserves:			
December 31, 2009	3,686	—	3,686
December 31, 2010	3,406	—	3,406
December 31, 2011	3,101	—	3,101
December 31, 2012	4,347	—	4,347

(1) Estimated quantities of oil and natural gas reserves in Mboe equivalents at a rate of six Mcf per Bbl.

The change in quantities of proved reserves during the period from December 31, 2009 through December 31, 2010 is due to (i) increases in oil prices during this time period, (ii) acquisitions of third party interests in existing waterflood units, (iii) infill drilling in our Battle Springs and Highlands waterflood units which resulted in an upward revision of oil in place and therefore recoverable reserves, and (iv) production responses from our existing waterflood units that exceeded earlier projections.

The change in quantities of proved reserves from December 31, 2010 to December 31, 2011 is due to (i) increases in oil prices during this time period, (ii) acquisitions of the War Party I and II Units in the Hugoton

Basin, J&A Oil Company interests in the Cushing Field, and third party interests in the Cleveland Field, (iii) infill drilling in our Ardmore West and Twin Forks waterflood units which resulted in an upward revision of oil in place and therefore recoverable reserves, and (iv) revisions of previous estimates for the balance of our properties.

The change in quantities of proved reserves from December 31, 2011 to December 31, 2012 is due to (i) the acquisitions of additional interests in our Southern Oklahoma units; (ii) the acquisition of additional working interest in our War Party I and II Unitsunits in the Hugoton Basin area; (iii), the acquisition of the Clawson Ranch Waterflood Unitunit in the Hugoton Basin area;, and (iv) the acquisition of additional properties in the Northeastern Oklahoma area.

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 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, 2012, 2011 and 2010, 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 reserves were based on costs determined at each such period-end, assuming the continuation of existing economic conditions.
- No future income tax expenses are computed for Mid-Con Energy Partners, LP because we are a non-taxable entity.
- Future net cash flows were discounted at an annual rate of 10%.

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

	Year Ended December 31,		
	2012	2011	2010
		(in thousands)	
Future cash inflows	$1,191,410	$ 930,788	$ 529,309
Future production costs	(417,362)	(297,490)	(152,913)
Future development costs	(47,490)	(34,504)	(26,802)
Future net cash flow	726,558	598,794	349,594
10% discount for estimated timing of cash flow	(323,136)	(270,563)	(165,932)
Standardized measure of discounted cash flow	$ 403,422	$ 328,231	$ 183,662

The prices utilized in calculating our total proved reserves were $94.71, $96.19, and $79.43 per Bbl of oil and $2.75, $4.11 and $4.37 per MMBtu of natural gas for December 31, 2012, 2011, and 2010, 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 $91.03, $93.20 and $74.26 per Bbl of oil and $2.87, $7.04 and $7.36 per Mcf of natural gas for December 31, 2012, 2011 and 2010, respectively. Adjusted natural gas price includes the sale of associated natural gas liquids. 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 gas reserves is presented below for the periods indicated:

	Year Ended December 31,		
	2012	2011	2010
Standardized measure of discounted future net cash flow, beginning of period	$ 328,231	$183,662	$105,800
Changes in the year resulting from:			
Sales, less production costs	(48,648)	(27,671)	(11,212)
Revisions of previous quantity estimates	(18,653)	26,960	(9,278)
Extensions, discoveries and improved recovery	51,098	26,128	16,562
Net change in prices and production costs	(112,688)	79,618	44,773
Net change in income taxes	—	—	—
Changes in estimated future development costs	(11,515)	(30,521)	(2,170)
Previously estimated development costs incurred during the period	21,629	31,968	9,242
Purchases of minerals in place	81,602	20,200	22,330
Accretion of discount	32,823	18,366	10,580
Timing differences and other	79,543	(479)	(2,965)
Standardized measure of discounted future net cash flow, end of year	$ 403,422	$328,231	$183,662

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

None.

ITEM 9A. CONTROL AND PROCEDURES

Evaluation of Disclosure Controls and Procedures.

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our chief executive officer (principal executive officer) and chief financial officer (principal financial officer), the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2012. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on this evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this Form 10-K.

Management's Report on Internal Control over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Mid-Con Energy Partners, L.P.'s internal control over financial reporting was effective as of December 31, 2012.

/s/ Charles R. Olmstead	/s/ Jeffrey R. Olmstead
Charles R. Olmstead	Jeffrey R. Olmstead
Chief Executive Officer	President and Chief Financial Officer

March 6, 2013

As a company with less than $1.0 billion in revenue during its last fiscal year, we qualify as an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. As an emerging growth company we may take advantage of specified reduced reporting and other regulatory requirements for up to five years that are otherwise applicable generally to public companies. As an emerging growth company we are taking the exemption from the auditor attestation requirement on the effectiveness of our system of internal control over financial reporting.

Change in Internal Controls Over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the period covered by this Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVES OFFICERS AND CORPORATE GOVERNANCE

As is the case with many publicly traded partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by our general partner. References to our officers and board of directors therefore refer to the officers and board of directors of our general partner. Our general partner is owned and controlled by the Founders.

Our general partner is not elected by our unitholders and is not subject to re-election on an annual or other continuing basis in the future. In addition, our unitholders are not entitled to elect the directors of our general partner, or directly or indirectly participate in our management or operations. Further, our partnership agreement contains provisions that substantially restrict the fiduciary duties that our general partner would otherwise owe to our unitholders under Delaware law.

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

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

Directors and Executive Officers

Each of the directors and officers, except Mr. Pekar, has served in their current position since the Initial Public Offering. The following table sets forth certain information regarding the current directors and executive officers of our general partner.

Name	Age	Position with Mid-Con Energy GP, LLC
S. Craig George	60	Executive Chairman of the Board
Charles R. "Randy" Olmstead	64	Chief Executive Officer and Director
Jeffrey R. Olmstead	36	President, Chief Financial Officer and Director
David A. Culbertson	47	Vice President and Chief Accounting Officer
Nathan P. Pekar	37	Vice President and General Counsel
Peter A. Leidel	56	Director
Cameron O. Smith (i)	62	Director
Robert W. Berry (i)	89	Director
Peter Adamson III (i)	71	Director

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

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

S. Craig George serves as Executive Chairman of the board of directors of our general partner. Mr. George has been a member of the board of directors of Mid-Con Energy III, LLC, Mid-Con Energy IV, LLC and Mid-Con Energy Operating since June 2011. Mr. George was a member of the board of directors of Mid-Con Energy I, LLC and Mid-Con Energy Operating since 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. From 1991 to 2004, Mr. George served in various executive positions at Vintage Petroleum, Inc., including President, Chief Executive Officer and as a member of the board of directors. In 1981, Mr. George joined Santa Fe Minerals, Inc. where he served until 1991 in executive positions including Vice President of Domestic Operations and Vice President-International. From 1975-1981, Mr. George held engineering and management positions with Amoco Production Company. Mr. George is a graduate of Missouri University of Science and Technology, with a Bachelor of Science degree in Mechanical Engineering, and of Aquinas Institute, with a Master of Arts in Theology. Over the course of his lengthy career in the oil and gas industry, Mr. George has gained extensive management and operational experience and has demonstrated a strong record of leadership, strategic vision and risk management. In light of Mr. George's extensive industry and managerial experience and knowledge, the Founders have concluded that Mr. George should continue to serve as a member of our board of directors.

Charles R. "Randy" Olmstead serves as Chief Executive Officer and as a member of the board of directors of our general partner. Mr. Olmstead has been Chief Executive Officer and Chairman of the board of directors of Mid-Con Energy III, LLC and Mid-Con Energy IV, LLC since June 2011. Mr. Olmstead served as President, Chief Financial Officer and Chairman of the board of directors of Mid-Con Energy I, LLC from its formation in 2004 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. He has been President, Chief Financial Officer and Chairman of the board of directors of Mid-Con Energy Operating since its incorporation in 1986. Prior to that, Mr. Olmstead was general manager for LB Jackson Drilling Company from 1978 to 1980 and worked in public accounting for Touche Ross & Co. from 1974 to 1978 as an oil and gas tax consultant. Mr. Olmstead graduated from the University of Oklahoma with Bachelors of Business Administration degrees in finance and accounting before serving three years in the US Navy. Mr. Olmstead's extensive management and operational experience in the oil and gas industry, along with his leadership skills, provides a critical resource to the board of directors. Because of Mr. Olmstead's extensive management, operational experience and leadership skills, the Founders have concluded that Mr. Olmstead should continue to serve as a member of our board of directors.

Jeffrey R. Olmstead serves as President, Chief Financial Officer and as a member of the board of directors of our general partner. Mr. Olmstead has been a member of the board of directors of Mid-Con Energy III, LLC and President, Chief Financial Officer and a member of the board of directors of Mid-Con Energy IV, LLC since June 2011. Mr. Olmstead was a member of the board of directors of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC from 2007 until both entities were merged into us in December 2011. Mr. Olmstead previously served as Chief Financial Officer and Vice President of Primexx Energy Partners, Ltd., a privately held exploration and production company, from May 2010 until July 2011. From August 2006 until May 2010, Mr. Olmstead served as an Assistant Vice President at Bank of Texas/Bank of Oklahoma. Mr. Olmstead is a graduate of Vanderbilt University, with a Bachelor of Engineering degree in Electrical Engineering and Math, and of the Owen School of Business at Vanderbilt University, with a Master of Business Administration. Mr. Olmstead's knowledge of the oil and gas industry and his finance background will provide a critical resource to our board of directors, and the Founders have concluded that he should continue to serve as a director.

David A. Culbertson serves as Vice President and Chief Accounting Officer of our general partner. Mr. Culbertson has served as Controller of Mid-Con Energy I, LLC from 2006 and of Mid-Con Energy II, LLC from its formation in 2009 until both entities were merged into us in December 2011. He has also supervised the accounting function for affiliates of our predecessor. Prior to joining us in 2006, Mr. Culbertson served in various accounting positions with Vintage Petroleum from 2003-2006, the Williams Companies from 1999-2003 and Samson Resources from 1989-1999. Mr. Culbertson is a graduate of Oklahoma State University, with a Bachelor of Business Administration degree in accounting, and of the University of Tulsa, with a Master of Business Administration. He is a Certified Public Accountant.

Nathan P. Pekar serves as Vice President of Business Development, General Counsel and Secretary of our general partner. Mr. Pekar became an officer of our general partner in April 2012. Prior to joining us, Mr. Pekar served as General Counsel and Business Development Manager with Matador Resources Company, from 2007-2012. Prior to this, Mr. Pekar was in private practice from 2003 to 2007. Mr. Pekar is a graduate of the University of Texas at Austin, with a Bachelor of Business Administration degree in Finance, and of Southern Methodist University School of Law, with a Juris Doctor degree. He is a licensed attorney in the State of Texas.

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

Cameron O. Smith serves as a member of the board of directors of our general partner and is also chairman of the conflicts committee. Mr. Smith founded and from 1992 to 2008, served as a Senior Managing Director of COSCO Capital Management LLC, an investment bank focused on private oil and gas corporate and project financing until Rodman & Renshaw, LLC, a full service investment bank, purchased the business and assets of COSCO Capital Management LLC. From 2008 until December 2009, Mr. Smith served as a Senior Managing Director of Rodman & Renshaw, LLC and as Head of The Rodman Energy Group, a sector vertical within Rodman & Renshaw, LLC. Mr. Smith retired from The Rodman Energy Group in December 2009. Mr. Smith founded and ran Taconic Petroleum Corporation, an exploration company headquartered in Tulsa, Oklahoma from 1978 to 1991. Mr. Smith served as exploration geologist, officer and director of several private family and public client companies from 1975 to 1985. Mr. Smith attended Princeton University receiving an A.B. in Art History in 1972 and Pennsylvania State University receiving a Master of Science in Geology in 1975. As a result of Mr. Smith’s extensive knowledge of the oil and natural gas industry, along with his expertise in investment banking, the Founders have concluded that he should continue to serve as a member of our board of directors.

Robert W. Berry serves as a member of the board of directors of our general partner. Mr. Berry is founder, Chief Executive Officer and President of Robert W. Berry, Inc., Empress Gas Corp. Ltd., R.W. Berry Canada, Inc. and Berry Ventures, Inc. which produce oil and gas in Oklahoma, Texas, Arkansas, North Dakota and Canada, and has served in these positions for more than the past five years. Mr. Berry has drilled and discovered numerous oil fields in Texas, North Dakota and Canada since working for Amerada Petroleum Corporation as a geologist. Mr. Berry graduated from the University of Oklahoma with a Bachelor of Science degree in Geology. Because of the technical knowledge and experience he has garnered over the last 60 years in the oil and natural gas business, the Founders have concluded that he should continue to serve as a member of our board of directors.

Peter Adamson III serves as a member of the board of directors of our general partner and is also chairman of the audit committee. Mr. Adamson is currently managing member of Autumn Glory Partners, LLC, a private consulting firm. Prior to Autumn Glory Partners, LLC, Mr. Adamson was a founder of Adams Hall Asset Management LLC, a Tulsa, Oklahoma based registered investment advisor with over $1 billion under management and remains a consultant. Prior to forming Adams Hall in 1997, Mr. Adamson was an owner and principal of Houchin, Adamson & Co., Inc., a registered broker-dealer formed in 1980. Mr. Adamson is founding co-investor and advisor to Horizon Well Logging, a leading provider of geological field services. Mr. Adamson serves on the advisory board of the Michel F. Price College of Business at the University of Oklahoma and serves on the University of Oklahoma asset oversight committee. Mr. Adamson received his Bachelor of Business Administration degree in accounting from the University of Oklahoma. As a result of Mr. Adamson's knowledge of finance and accounting the Founders have concluded that he provides a critical resource and skill set to our board of directors and the Founders have concluded that he should continue to serve as a member of our board of directors.

Committees of the Board of Directors

Mid-Con Energy GP, LLC's board of directors has an audit committee and a conflicts committee. The Audit Committee charter is posted under the "Investor Relations" section of our website at www.midconenergypartners.com. We do not have a compensation committee. The NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee or a nominating and corporate governance committee.

We are, however, required to have an audit committee, a majority of whose members are required to be "independent" under NASDAQ standards. Our board of directors or an appointed committee, currently comprised of the Founders, approve equity grants to directors and employees.

Audit Committee

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

The audit committee held five meetings in 2012. The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary.

Conflicts Committee

The conflicts committee consists of Messrs. Berry, Smith and Adamson, all of whom meet the independence standards established by the NASDAQ listing rules and rules of the SEC. The conflicts committee has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict is "fair and reasonable" for our unitholders. In making such determination, the conflicts committee has the authority to engage advisors to assist it in carrying its duties. The conflicts committee held no meetings in 2012.

Board Leadership Structure and Role in Risk Oversight

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

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

Non-Management Executive Sessions and Unitholder Communications

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

Interested parties can communicate directly with non–management directors by mail in care of Mid-Con Energy Partners, LP, 2501 North Harwood Street, Suite 2410, Dallas Texas 75201. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Meetings and Other Information

The board of directors held five meetings in 2012.

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and directors of our general partner and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and the NASDAQ concerning their beneficial ownership of such securities. Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of our general partner, we believe that all filing requirements applicable to the officers and directors of our general partner and greater than 10% unitholders were complied with for the fiscal year ended December 31, 2012, with the exception of the following: Messrs. Olmstead and George filed a Form 4 on August 8, 2012 with respect to a reportable transaction on July 31, 2012. Mr. Berry filed a Form 4 on February 4, 2013 with respect to a reportable transaction on December 14, 2012. Mr. Jones filed a Form 4 on December 27, 2012 with respect to a reportable transaction on September 20, 2012.

Code of Ethics

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

Mid-Con Energy GP, LLC has adopted a Code of Business Conduct that applies to all officers, directors and employees of Mid-Con Energy GP, LLC and its affiliates. A copy of our Code of Business Conduct is available on our website at www.midconenergypartners.com. We will provide a copy of our code of ethics to any person, without charge, upon request to Mid-Con Energy GP, LLC, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201, Attn: Investor Relations.

Web Access

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

Communication with Directors

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

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General

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

Compensation Committee Report

The NASDAQ listing rules do not require a listed limited partnership to establish a compensation committee, and we do not have a compensation committee. The board of directors of our general partner performs the functions of a compensation committee, and although the board of directors of our general partner does not currently intend to establish a compensation committee, it may do so in the future.

The board of directors of our general partner has reviewed and discussed with management the Compensation Discussion and Analysis, or CD&A, set forth below. Based on this review and discussion, the board of directors determined that the CD&A be included in this Annual Report on Form 10-K for the year ended December 31, 2012.

Submitted by: S. Craig George
Charles R. "Randy" Olmstead
Jeffrey R. Olmstead
Peter A. Leidel
Cameron O. Smith
Robert W. Berry
Peter Adamson III

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

Objectives of Our Compensation Program

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

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

Elements of Our Compensation Program and Why We Pay Each Element

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

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

We and our general partner were formed in July 2011; therefore, we incurred no cost or liability with respect to the compensation of our executive officers, nor has our general partner accrued any liabilities for management incentive or retirement benefits for our executive officers for the fiscal year ended December 31, 2010 or for any prior periods. Accordingly, we are not presenting any compensation information for historical periods.

The Founders, as the controlling members of our general partner, have responsibility and authority for compensation-related decisions for our Chief Executive Officer and, upon consultation and recommendations by our Chief Executive Officer, for our other executive officers. Equity grants pursuant to our long-term incentive program are also administered by the Founders.

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

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

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

Employment Agreements

Our general partner has entered into employment agreements with each of the following named employees of our general partner: Charles R. Olmstead, Chief Executive Officer; Jeffrey R. Olmstead, President and Chief Financial Officer; and S. Craig George, Executive Chairman of the Board of our general partner.

The employment agreements provide for a term that commenced on August 1, 2011 and expires on August 1, 2014, unless earlier terminated, with automatic one-year renewal terms unless either we or the employee gives written notice of termination at least by February 1 preceding any such August 1. Pursuant to the employment agreements, each employee will serve in his respective position with our general partner, as set forth above, and has duties, responsibilities, and authority as the board of directors of our general partner may specify from time to time, in roles consistent with such positions that are assigned to him.

The employment agreements also provide for customary confidentiality, non-solicitation, non-compete and indemnification protections. The non-solicitation provisions prohibit an executive from soliciting persons to leave our employment who are employed by us within six months before or after the executive's termination. This restriction continues during the term of and for twelve months following termination of the executive's employment, and also for twelve months following the termination of the solicited employee's employment. The non-solicitation provisions also prohibit an executive from soliciting our customers during the term of and for twelve months following termination of the executive's employment. The non-competition provisions prohibit the executive from competing with us during the term of the executive's employment and for a period during which severance payments are being made to the executive, which by the terms of the agreements may be up to two years after the executive's separation of employment.

Long-Term Incentive Program

Our Long-Term Incentive Program which is intended to promote the interests of the partnership by providing to employees, officers, consultants and directors of our general partner and our other affiliates, including Mid-Con Energy Operating, 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 other affiliates, including Mid-Con Energy Operating, to attract and retain the services of individuals who are essential for the growth and profitability of the partnership and to encourage them to devote their best efforts to advancing the business of the partnership.

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

The type of awards that may be granted under the Long-Term Incentive Program are restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The maximum number of our common units that are currently authorized to be awarded under the Plan is 1,764,000 million units. As of December 31, 2012 there were 1,413,151 units available for issuance.

Equity Compensation Plan Information:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	—	1,413,151 common units
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	1,413,151 common units

The plan administrator may terminate or amend the Plan 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 Plan or any part of the Plan 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 Plan 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 Plan), any change in applicable law or regulation affecting the Plan 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 Plan may, in its discretion, provide that awards will (i) become exercisable or payable, as applicable, (ii) be exchanged for cash, (iii) be replaced with other rights or property selected by the plan administrator, (iv) be assumed by the successor or survivor entity or be exchanged for similar options, rights or awards covering the equity of such successor or survivor, or a parent or subsidiary thereof, with other appropriate adjustments or (v) be terminated. Additionally, the plan administrator may also, in its discretion, make adjustments to the terms and conditions, vesting and performance criteria and the number and type of common units, other securities or property subject to outstanding awards.

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

Common units to be delivered pursuant to awards under the Plan 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 Plan, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash, our general partner will be entitled to reimbursement by us for the amount of the cash settlement.

Short-Term Incentive Payments

The performance criteria for the short-term incentive plan for 2011 included 50% of the target bonus earned upon the successful completion of the Initial Public Offering and 50% earned upon successful completion of the requirements allowing common units issued to the Founders in conjunction with the Initial Public Offering that will initially be restricted from trading to no longer be so restricted. The performance criteria for the short-term incentive plan for 2012 and future years include 50% of the target bonus earned for meeting initial quarterly distribution goals, 20% earned for generating an increase in the amount of distributions from the preceding year, 20% earned for generating additions of new reserves and growth of distributions based on aggregate acquisitions of 10% growth, and 10% earned for overall performance as determined by our board. We do not provide perquisites to the named executive officers.

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers for services rendered in all capacities to us and our subsidiaries for the years ended December 31, 2012 and 2011. 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. There was not a service agreement in place prior to December 2011; therefore, no salaries were allocated prior to December 2011.

Name and Principal Position	Year	Salary	Bonus	Unit Awards	Compensation	Total
Charles R. Olmstead	2012	$186,292	$—	$1,275,000	$—	$1,461,292
Chief Executive Officer	2011	15,361	—	—	—	15,361
S. Craig George	2012	$236,897	$—	$1,275,000	$—	$1,511,897
Executive Chairman of the Board	2011	17,270	—	—	—	17,270
Jeffrey R. Olmstead	2012	$324,763	$—	$1,275,000	$—	$1,599,763
President, Chief Financial Officer	2011	27,024	—	—	—	27,024
David A. Culbertson	2012	$165,927	$—	$ 149,175	$—	$ 315,102
Vice President, Chief Accounting Officer	2011	11,668	—	—	—	11,668
Nathan P. Pekar	2012	$167,443	$—	$ 385,045	$—	$ 552,488
Vice President, General Counsel	2011	—	—	—	—	—

Grants of Plan-Based Awards

The following table sets forth certain information with respect to grants of performance units to our named executive officers in 2012. There were no grants of non-equity incentives or option awards.

Name	Grant Date	Unit Awards	Grant Date Fair Value of Unit Awards
Charles R. Olmstead	1/31/2012	25,000	$522,500
	7/31/2012	35,000	752,500
S. Craig George	1/31/2012	25,000	522,500
	7/31/2012	35,000	752,500
Jeffrey R. Olmstead	1/31/2012	25,000	522,500
	7/31/2012	35,000	752,500
David A. Culbertson	1/31/2012	5,000	104,500
	11/15/2012	2,500	44,675
Nathan P. Pekar	7/31/2012	5,000	107,250
	11/15/2012	3,500	62,615

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2012.

Name	Number of Units That Have Not Yet Vested	Market Value of Units That Have Not Yet Vested (1)
Nathan P. Pekar	10,000(2)	$215,000

(1) Based on the closing price of our common units when the units were awarded at July 31, 2012.
(2) These restricted units vest 33% each year beginning July 31, 2013.

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

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

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

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

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

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

- accelerated vesting and conversion of any units which may have been awarded to the officer through our long-term incentive program, in accordance with the terms of the applicable award agreement;

- a lump sum payment to compensate the officer or the officer's estate for COBRA health-care coverage for the officer (if living) and the officer's dependents (if applicable);
- a payment equal to the product of the officer's base salary as in effect immediately prior to the date of termination multiplied by one;
- payment of any unpaid annual bonus that would have become payable to the officer in respect of any calendar year that ends on or before the date of termination had the officer remained employed through the payment date of such annual bonus; and
- payment of the target annual bonus for the year in which the officer's separation from service occurs.

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

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

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

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

- any "person" or "group" within the meaning of those terms as used in Sections 13(d) and 14(d) of the Exchange Act, other than certain of our affiliated entities, shall become the beneficial owner, directly or indirectly, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in us;
- a plan of complete liquidation, in one or a series of transactions, is approved;
- the sale or other disposition by us of all or substantially all of our assets in one or more transactions to any person other than certain of our affiliated entities;
- a transaction resulting in a person other than us or one of certain of our affiliated entities being our general partner; or

- any time at which individuals who, as of October 31, 2011, constitute our Board of Directors (the "Incumbent Board") cease for any reason to constitute at least a majority of our Board; *provided, however*, that any individual becoming a director subsequent to October 31, 2011, whose election, or nomination for election by our unitholders was approved by a vote of at least a majority of the directors then comprising the Incumbent Board or whose membership was required by any employment agreement with us will be considered as though such individuals were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as the result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a person other than the Incumbent Board.

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

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

Potential Post-Employment Payment Tables – The following tables reflect estimates of our allocated portion of the amount of incremental compensation due to each named executive officer subject to an employment agreement in the event of such executive's termination of employment upon death, disability or retirement, termination of employment without cause or termination of employment without cause or with good reason within three years following a change in control. The amounts shown assume that such termination was effective as of December 31, 2012, and are estimates of the allocated amounts which would be paid out to the executives upon such termination. The actual amounts to be paid out can only be determined at the time of such executive's separation of service.

S. Craig George	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 640,000	$ 480,000	$ 480,000
Equity	—	—	—
Restricted Stock/Units	—	—	—
Performance Shares/Units	1,122,000	1,122,000	1,122,000
Total	1,762,000	1,602,000	1,602,000
Other Benefits	—	—	—
Health & Welfare	15,428	15,428	15,428
Tax Gross-Ups	—	—	—
Total	15,428	15,428	15,428
Total	$1,777,428	$1,617,428	$1,617,428

Charles R. Olmstead	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 640,000	$ 480,000	$ 480,000
Equity	—	—	—
Restricted Stock/Units	—	—	—
Performance Shares/Units	1,122,000	1,122,000	1,122,000
Total	1,762,000	1,602,000	1,602,000
Other Benefits	—	—	—
Health & Welfare	15,428	15,428	15,428
Tax Gross-Ups	—	—	—
Total	15,428	15,428	15,428
Total	$1,777,428	$1,617,428	$1,617,428

Jeffrey R. Olmstead	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following Change in Control**
Cash Severance	$ 760,000	$ 720,000	$ 720,000
Equity	—	—	—
Restricted Stock/Units	—	—	—
Performance Shares/Units	1,122,000	1,122,000	1,122,000
Total	1,882,000	1,842,000	1,842,000
Other Benefits	—	—	—
Health & Welfare	21,182	21,182	21,182
Tax Gross-Ups	—	—	—
Total	21,182	21,182	21,182
Total	$1,903,182	$1,863,182	$1,863,182

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 of directors of our general partner does not currently intend to 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 2012, directors who were not officers or employees of us or our affiliates received an annual retainer of $40,000, 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 committee meeting attended in person or by phone and is reimbursed for his out of pocket expenses in connection with attending meetings. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

Each of the independent directors were awarded 2,500 common units in January 2012. The common units were fully vested at the grant date.

The following table discloses the cash unit awards and other compensation earned, paid or awarded to each of our directors during the year ended December 31, 2012:

Name (1)	Fee Earned or Paid in Cash	Unit Awards (2)	Total
Peter Adamson III	$54,000	$52,250	$106,250
Cameron O. Smith	52,000	52,250	104,250
Robert W. Berry	49,000	52,250	101,250
Peter A. Leidel	44,000	52,250	96,250

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

(2) Reflects the fair value of the units granted in January 2012.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

As of March 5, 2012, the following table sets forth the beneficial ownership of our common units that are owned by:

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

Name of Beneficial Owner	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Yorktown Energy Partners VI, L.P. (1)(2)	1,855,165	9.6%
Yorktown Energy Partners VII, L.P. (1) (3)	927,583	4.8%
Yorktown Energy Partners VIII, L.P. (1)(4)	2,308,720	12.0%
Kayne Anderson Capital Advisors, L.P./Richard A. Kayne (6)(7)	1,503,215	7.8%
Charles R. Olmstead (5)	650,278	3.4%
Jeffrey R. Olmstead (5)	280,329	1.5%
S. Craig George (5)	254,585	1.3%
David A. Culbertson (5)	80,583	0.4%
Nathan P. Pekar (5)	12,500	0.1%
Peter Adamson III (5)	15,000	0.1%
Robert W. Berry (5)	30,459	0.2%
Peter A. Leidel (5)	6,500	0.0%
Cameron O. Smith (5)	11,293	0.1%
All named executive officers, directors and director nominees as a group (10 persons)	1,341,527	7.0%

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

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

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

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

(5) c/o Mid-Con Energy GP, LLC, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201

(6) Has a principal business address of 1800 Avenue of the Starts, 3rd Floor, Los Angeles, CA 90067.

(7) This information has been derived from a Schedule 13G filed with the SEC on January 10, 2013. Based on the information contained in the filing, Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have shared voting power and dispositive power with respect to, and beneficially own, an aggregate of 1,503,215 common units.

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

Name of Beneficial Owner	Member Interest(2)
Charles R. Olmstead(1)	33.33%
S. Craig George(1)	33.33%
Jeffrey R. Olmstead(1)	33.33%

(1) c/o Mid-Con Energy GP, LLC, 2501 North Harwood Street, Suite 2410, Dallas, Texas 75201

(2) Messrs. Olmstead, George, and Olmstead, 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, George and Olmstead disclaims beneficial ownership of these securities in excess of his pecuniary interest in such securities.

Securities Authorized for Issuance under Equity Compensation Plan

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

As of December 31, 2012, our general partner has an approximate 1.9% interest in us. The distributions we will make to our general partner are described under Item 5.

Agreements with Affiliates in Connection with the Transactions

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

Reimbursement of Expenses

We entered into 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 to us, which include marketing, geological and engineering services. Under the services agreement, we reimburse Mid-Con Energy Operating, on a monthly basis, for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by Mid-Con Energy Operating to us. Mid-Con Energy Operating has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us. Mid-Con Energy Operating will not be liable to us for its performance of, or failure to perform, services under the services agreement unless its acts or omissions constitute gross negligence or willful misconduct. For the year ended December 31, 2012, we reimbursed Mid-Con Energy Operating approximately $2.9 million for direct operating expenses.

Other Transactions with Related Persons

Operating Agreements

We, various third parties with an ownership interest in the same property and our affiliate, Mid-Con Energy Operating, are party to standard oil and gas joint operating agreements, pursuant to which we and those third parties pay Mid-Con Energy Operating overhead charges associated with operating our properties (commonly referred to as the Council of Petroleum Accountants Societies, or COPAS, fee). We and those third parties pay Mid-Con Energy Operating for its direct and indirect expenses that are chargeable to the wells under their respective operating agreements.

Review, Approval or Ratification of Transactions with Related Persons

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

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

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

Director Independence

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of Mid-Con Energy GP, LLC selected Grant Thornton LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the year ended December 31, 2012 and 2011. The audit committee's charter requires the audit committee to approve in advance all audit and non–audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit–related, tax and all other fees categories below with respect to this Annual Report on Form 10–K for the year ended December 31, 2012 were approved by the audit committee.

Fees paid to Grant Thornton LLP are as follows:

	2012	2011
Audit fees	$277,769	$488,144
Audit-Related	$ 10,000	$ —
Tax fees	$115,075	$ 62,256
Total	$402,844	$550,400

PART IV

ITEM 15. EXHIBITS

(a)(1) *Exhibits*

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Mid-Con Energy Partners, LP (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP's registration statement on Form S-1 filed with the SEC on August 12, 2011 (File No.333-176265)).
3.2	Certificate of Formation of Mid-Con Energy GP, LLC (incorporated by reference to Exhibit 3.4 to Mid-Con Energy Partners, LP's registration statement on Form S-1 filed with the SEC on August 12, 2011 (File No. 333-176265)).
3.3	First Amended and Restated Agreement of Limited Partnership of Mid-Con Energy Partners, LP, dated as of December 20, 2011 (incorporated by reference to Exhibit 3.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
3.4	Amended and Restated Limited Liability Company Agreement of Mid-Con Energy GP, LLC, dated as of December 20, 2011 (incorporated by reference to Exhibit 3.2 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.1	Services Agreement, dated as of December 20, 2011, by and among Mid-Con Energy Operating, Inc., Mid-Con Energy GP, LLC, Mid-Con Energy Partners, LP and Mid-Con Energy Properties, LLC (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.2	Agreement and Amendment No. 2 to Credit Agreement, dated as of November 26, 2012, among Mid-Con Energy Properties, LLC, as Borrower, Royal Bank of Canada, as Administrative Agent and Collateral Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on November 28, 2012).
10.3	Contribution, Conveyance, Assumption and Merger Agreement, by and among Mid-Con Energy GP, LLC, Mid-Con Energy Partners, LP, Mid-Con Energy Properties, LLC, Mid-Con Energy I, LLC, Mid-Con Energy II, LLC and Charles R. Olmstead, S. Craig George, Jeffrey R. Olmstead and other members of Mid-Con Energy I, LLC and Mid-Con Energy II, LLC named therein (incorporated by reference to Exhibit 10.3 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.4	Mid-Con Energy Partners, LP Long-Term Incentive Program (incorporated by reference to Exhibit 4.5 to Mid-Con Energy Partners, LP's Registration Statement on Form S-8 filed with the SEC on January 25, 2012 (File No 333-179161)).
10.5	Form of Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.6	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and Charles R. Olmstead (incorporated by reference to Exhibit 10.6 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).

10.7	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and Jeffrey R. Olmstead (incorporated by reference to Exhibit 10.7 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.8	Employment Agreement, dated as of August 1, 2011, by and among Mid-Con Energy Partners, LP, Mid-Con Energy GP, LLC and S. Craig George (incorporated by reference to Exhibit 10.8 to Mid-Con Energy Partners, LP's current report on Form 8-K filed with the SEC on December 23, 2011).
10.9	Purchase and Sale Agreement dated October 15, 2012 and filed of record in the Partnership's Amended S-1 dated October 15, 2012 (incorporated by reference to Exhibit 10.9 to Mid-Con Energy, LP's Amendment No. 1 to the Registration Statement on Form S-1 dated October 15, 2012 (File NO. 333-184120)).
10.10	Form of Crude Oil Purchase Agreement between Mid-Con Energy Operating, Inc. and Enterprise Crude Oil LLC.
21.1	Subsidiaries of Mid-Con Energy Partners, LP
23.1+	Consent of Cawley, Gillespie & Associates, Inc.
23.2+	Consent of Grant Thornton LLP
31.1+	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2+	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1+	Section 1350 Certification of Chief Executive Officer
32.2+	Section 1350 Certification of Chief Financial Officer
99.1+	Cawley, Gillespie & Associates, Inc. Reserve Report
101.INS++	XBRL Instance Document
101.SCH++	XBRL Taxonomy Extension Schema Document
101.CAL++	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF++	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB++	XBRL Taxonomy Extension Label Linkbase Document
101.PRE++	XBRL Taxonomy Extension Presentation Linkbase Document

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

\+ Filed herewith
++ Furnished herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Mid-Con Energy Partners, LP
(Registrant)

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

Date: March 6, 2013

By: */s/ Jeffrey R. Olmstead*
Jeffrey R. Olmstead
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 6, 2013.

Signature	Title	Date
/s/ Charles R. Olmstead Charles R. Olmstead	Chief Executive Officer and Director (Principal Executive Officer)	March 6, 2013
/s/ Jeffrey R. Olmstead Jeffrey R. Olmstead	President, Chief Financial Officer and Director (Principal Financial Officer)	March 6, 2013
/s/ David A. Culbertson David A. Culbertson	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 6, 2013
/s/ Peter A. Leidel Peter A. Leidel	Director	March 6, 2013
/s/ Cameron O. Smith Cameron O. Smith	Director	March 6, 2013
/s/ Robert W. Berry Robert W. Berry	Director	March 6, 2013
/s/ Peter Adamson III Peter Adamson III	Director	March 6, 2013
/s/ S. Craig George S. Craig George	Executive Chairman of the Board	March 6, 2013

Executive Management & Directors

Executive Management

S. Craig George
Executive Chairman of the Board

Charles R. Olmstead
Chief Executive Officer

Jeffrey R. Olmstead
President, Chief Financial Officer

Michael L. Wiggins
Executive Vice President, Chief Engineer

David A. Culbertson
Chief Accounting Officer

Nathan P. Pekar
Vice President of Business Development, General Counsel

Board of Directors

Peter Adamson III *(i)(a)(c)*

C. Fred Ball, Jr. *(i)(a)*

Robert W. Berry *(i)(a)(c)*

S. Craig George

Peter A. Leidel

Charles R. Olmstead

Jeffrey R. Olmstead

Cameron O. Smith *(i)(a)(c)*

Michael L. Wiggins

(i) Independent Director; (a) Member of the Audit Committee; (c) Member of the Conflicts Committee

Unitholder Information

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NASDAQ: MCEP

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Independent Accounting Firm

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Independent Reservoir Engineers

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